National Energy Board

The Sarnia-Montreal Pipeline

A Review and Report
by the
National Energy Board

April 1991

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Recital and Submittors

IN THE MATTER of the *National Energy Board Act ("the Act")* and the regulations made thereunder; and

IN THE MATTER OF a request dated 8 January 1991 from the Minister of Energy, Mines and Resources for an inquiry pursuant to Section 26, Part II of the *National Energy Board Act*.

BEFORE:

R. Priddle	Chairman
J.-G. Fredette	Vice Chairman
C. Bélanger	Member

SUBMITTORS:

Interprovincial Pipe Line Company, a division of Interhome Energy Inc. *
AEC Oil and Gas Company
Alberta Chamber of Resources
Alberta Petroleum Marketing Commission *
Amoco Canada Petroleum Company Ltd. *
Canadian Petroleum Association *
Esso Petroleum Canada *
Gaz Métropolitain
Gibson Petroleum Company Limited *
Husky Oil
Independent Petroleum Association of Canada *
Montreal Pipe Line Limited
New Brunswick Department of Natural Resources and Energy *
Norcen Energy Resources Limited
NOVA Petrochemicals Inc. *
Nova Scotia Department of Mines & Energy *
Ontario Ministry of Energy *
PanCanadian Petroleum Limited *
Petro-Canada Products *
Prince Edward Island Energy and Forestry
Procureur Général du Québec/Ministère de l'Énergie et des Ressources du Québec*
Saskatchewan Energy and Mines
Shell Canada Limited *
Suncor *
Trans-Northern Pipelines Inc.

* Meetings were held with these parties

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Glossary and Abbreviations

Act or NEB Act	*National Energy Board Act*
AERCB	Alberta Energy Resources Conservation Board
Board	National Energy Board
Brent (crude oil)	A grade of light, sweet crude oil produced in the North Sea which is the benchmark grade of oil for Atlantic Basin price quotations.
Capline	Refers to the crude oil pipeline system connecting the U.S. Gulf to refineries in the Chicago area.
Class 3 (NEB) Toll Hearing	A hearing pertaining to toll applications that involve consideration of methodology or rate of return.
CPA	Canadian Petroleum Association
CSA	Canadian Standards Association
Deficiency Agreement	An agreement entered into between the federal government and IPL supporting the Sarnia-Montreal pipeline.
EMR	Energy, Mines and Resources Canada
Esso	Esso Petroleum Canada
IEA	International Energy Agency
IPAC	Independent Petroleum Association of Canada
IPL	Interprovincial Pipe Line Company, a division of Interhome Energy Inc.
Mobil	Mobil Oil Canada, Ltd.
Mid-west (U.S.)	In the context of this report equivalent to PADD II
MSW	Sweet Mixed Blend
NEB	National Energy Board
Northern Tier	Those U.S. states bordering on Canada or the Great Lakes, excluding Alaska.
Older (IPL) System	That portion of the IPL system not including the Sarnia-Montreal extension.
PADD	United States Petroleum Administration for Defense District

PADD II	Comprises the States of North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, Minnesota, Iowa, Missouri, Wisconsin, Illinois, Michigan, Indiana, Ohio, Kentucky, Tennessee
Parity Point	The location at which competing grades of oil are equally priced.
Petro-Canada	Petro-Canada Products Inc.
Sarnia-Montreal pipeline	Referred to alternatively as the "Sarnia-Montreal extension", the "extension", the "Montreal extension", and "Line 9".
Shell	Shell Canada Products Ltd.
Sweet Mixed Blend (MSW)	A mixed blend of Canadian light, sweet crude oils transported on IPL.
TMPL	Trans Mountain Pipe Line Company Ltd.
WTI	West Texas Intermediate crude oil; a light, sweet crude oil produced in the United States which is the benchmark grade of oil for North American price quotations.

Chapter 1

Summary and Conclusions

The crude oil supply-demand situation for all of inland North America, and not just the Canadian supply-demand situation, is influencing, and will continue to influence, the use made of the Sarnia-Montreal pipeline. In this regard, there is a continuing decline in domestic supply, especially of conventional light sweet crude oil, in these regions which is being offset by increased imports. The situation is complicated by different product yields from various grades of light crude oil and by seasonal demand patterns for crude oil and oil products.

Canadian light sweet crude grades are now regarded by Montreal refiners as being generally uncompetitive with overseas crude. This factor has caused a reduction in total throughputs on the extension. The resulting long delivery times and high inventory costs have also made light sour and heavy crude grades uncompetitive in Montreal.

In Ontario, there is currently sufficient domestic crude oil available. Refiners there have varying views on when supplemental overseas supplies will be needed and how they should be provided. The most likely options are the reversal of the Sarnia-Montreal pipeline or imports of overseas oil via U.S. Gulf ports and connecting pipelines.

Security of supply is a particular concern for the governments of Quebec, New Brunswick, Prince Edward Island and Nova Scotia. Their comments extended into areas including strategic or tactical storage which the Board has not studied. However, it would appear that the Sarnia-Montreal pipeline itself can contribute to security of supply in varying degrees by being used for west to east flow, east to west flow or by being maintained in a useable state for flow in either direction.

Producers were particularly concerned about the currently wide differentials between light sweet crude oil and sour and heavy crude grades and the impacts on these differentials of the loss of access to the Montreal market. No information was received which would help the Board to quantify the impact on price differentials of sales through the Sarnia-Montreal line. Several reasons were advanced to support the view that differentials will soon narrow.

The major economic driving force for reversal of the Sarnia-Montreal pipeline is its potential to provide reliable competitive overseas crude oil supply to Ontario refineries. Without this supply, Ontario refiners will have to compete against land-locked American refiners for diminishing supplies of Canadian crude oils, particularly the lighter grades. Their ability to respond to increased feedstock prices may be limited by the poor profitability of the Ontario refining industry and competition from petroleum products imported from the United States.

The timing of a reversal, if shown to be required, will depend on individual companies' decisions as to the best means to secure feedstock supplies. The IPL toll methodology is a critical element in assessing reversal economics. This matter will be considered in a future Board hearing into IPL tolls, perhaps as early as this fall.

The primary option available to encourage continued west to east flow is for the federal government (or for IPL, or for IPL as agent for the government) to purchase the linefill. There do not, however, appear to be any immediate security of supply reasons for the government to take such action. On the contrary, there are sound reasons for governments not to intervene as producers sort out the most economic means to dispose of domestic crude oil supply and as refiners provide for longer term access to crude oil for their refineries.

There appear to be no serious engineering or environmental implications to continued west to east flow, reversal, or deactivation. At this point, the possibility exists for economic forces to take their course and for changes in the use of the pipeline to be addressed, as necessary, through NEB regulatory proceedings on tolls, pipeline safety or on new facilities required for reversal. IPL, in due course, and in response to shippers' plans and commitments, may bring these matters forward for decision.

Chapter 2

Introduction

In the summer and fall of 1990, in response to economic forces, Montreal refiners began to reduce receipts of Canadian crude oil shipped to them through the pipeline system operated by Interprovincial Pipe Line Company, a division of Interhome Energy Inc. ("IPL"). These lower throughputs resulted in greater scheduling difficulties and higher linefill costs for shippers. This prompted them to advise IPL that they intended to terminate shipments of Canadian crude oil to Montreal in the first quarter of 1991. Shippers subsequently requested that IPL prepare to deliver shipper-owned linefill to them in Montreal.

Given shippers' intentions, IPL began to plan for the idling and deactivation of the Sarnia-Montreal section of the pipeline and, to this end, contacted industry, governments, and the National Energy Board ("the Board" or "NEB") concerning the procedures required to effect deactivation.

Coincident with these developments was the invasion of Kuwait by Iraq on 2 August 1990 which, on 16 January 1991, led to war. As tensions in the Persian Gulf heightened and the possibility of oil supply disruption became a concern, the Minister of Energy, Mines and Resources, the Honourable Jake Epp, suggested to shippers that the Sarnia-Montreal line be maintained in an operational mode for the heating season. He also requested in a letter dated 8 January 1991 (Appendix I), that the Board review and report on the prospects for, and implications of, the closure of the Sarnia-Montreal pipeline and the options available for maintaining the line in an operating mode.

As part of its review, the Board invited written submissions from interested parties. Follow-up meetings with a number of respondents were held in Calgary and Ottawa when clarification of issues raised was deemed necessary.

The Sarnia-Montreal pipeline has been the subject of previous studies. These include reports by Energy, Mines and Resources published in June 1987 entitled "The Sarnia-Montreal Pipeline: An Evaluation of Prospects" and by the Board in September 1987 entitled "Ontario Oil Supply Logistics, 1986-2005". The present study draws on some material originally presented in these reports.

To the extent possible, the report has been organized to address directly the questions posed in the Minister's letter. The next section of the paper provides a brief background covering the history and recent events pertaining to the pipeline. The following two chapters discuss the major factors affecting eastern refiners' options for obtaining crude oil, namely, the supply and demand of domestic crude oil and the changing North American crude oil price patterns. These sections are followed by the Board's comments on security of supply, impacts on markets and prices, options for continued west to east flow, pipeline engineering and environmental considerations and regulatory processes.

Background

In 1973, Arab oil producing countries imposed an embargo on deliveries of crude oil to some western countries. This action threatened the supply of oil to refineries in Atlantic Canada and Quebec. Montreal refineries at that time were dependent upon overseas crude oil delivered by vessel either directly, or to Portland, Maine, and thence by the Portland-Montreal pipeline system (more fully described in Appendix II) to Montreal. Only limited volumes of oil produced in western Canada could be delivered to Atlantic and Quebec refineries. This was accomplished by shipping oil either through the pipeline system operated by Trans Mountain Pipe Line Company Ltd. ("TMPL") to Vancouver, and loading vessels which would transit the Panama Canal, or by tanker from Ontario ports down the St. Lawrence Seaway.

At the time of the embargo, the pipeline system operated by IPL (more fully described in Appendix

III) extended from Edmonton to the Toronto area, and delivered Canadian crude oil to both United States and Canadian refineries. As a result of the embargo, the vulnerability of the refineries in Atlantic Canada and Quebec became of greater concern to the government of Canada. IPL was therefore asked to consider an extension of its system to serve Montreal refineries and to permit Quebec City and Atlantic refiners, if circumstances warranted, to use existing dock facilities in Montreal to load vessels with Canadian crude for delivery further east.

To enhance security of supply for consumers in eastern Canada, the government of the day entered into an agreement with IPL to support the construction of the Sarnia-Montreal pipeline by guaranteeing any financial loss which might result from low throughputs. Details of the Deficiency Agreement, which covers the twenty-year period ending in 1996, are provided in Appendix IV.

The extension to Montreal was completed in 1976 and had a throughput capacity slightly in excess of 50 000 cubic metres per day. The line has the potential to be reversed at some additional capital cost so that imported crude oil could be transported to refineries in Ontario if such a need arises.

Current refining capacity in Montreal is about 30 000 cubic metres per day, compared to some 70 000 cubic metres per day in 1976. Through 1989 and into early 1990, about half of the Montreal requirement was supplied by domestic crude oil via the extension, and the remainder by offshore supplies via the Portland-Montreal pipeline system. In the first half of 1990, four shippers delivered an average of about 15 000 cubic metres per day of domestic crude oil to the two refineries in Montreal operated by Shell Canada Products Ltd. ("Shell") and Petro-Canada Products Inc. ("Petro-Canada"). Beginning in September 1990, three shippers - Esso Petroleum Canada ("Esso"), Petro-Canada and the Alberta Petroleum Marketing Commission - ceased nominating for delivery on the Montreal extension. Shell, the only remaining shipper, was left to carry the cost of the 368 000 cubic metres (2.3 million barrels) of linefill. Shell, in March 1991, requested of IPL that this volume be delivered to it; in late April 1991, IPL began displacing the linefill with nitrogen.

Chapter 3

Supply and Demand for Canadian Crude Oil

This chapter discusses projections for the supply of domestic light and heavy crude oils for the period to 2000, the outlook for petroleum product demand in Canada, and refinery feedstock requirements. It concludes with an analysis of the supply and demand balances, which focuses primarily on light crude oil.

3.1 Domestic Supply

Predominant trends in western Canadian crude oil supply can be characterized as follows:

- reserves additions of conventional crude oil have not been keeping pace with production;
- conventional light crude oil production, which currently represents more than half of Canada's crude oil supply capability, is declining; and
- the composition of Canada's crude oil supply is changing as the fraction of total supply that consists of heavy and synthetic crude oils is increasing.

It is in this context that the crude oil supply projections for the period to the year 2000 were developed. The control case is a projection which is based on a crude oil price that increases from $U.S. 20 to $U.S. 23 per barrel (1990 dollars) between 1990 and 2000. Appendix V provides details regarding the control case projection, the uncertainty around this control case, and views expressed by interested parties.

Table 3.1 illustrates the projection of light crude oil supply and the anticipated change in its composition. Aggregate supply from western Canada is expected to decline over the projection period due to the falling supply of conventional light crude oil. The decline may be offset somewhat by increased synthetic crude oil supply.

The supply of frontier crude oil, mainly from the Hibernia field, is expected to develop over the projection period but is not directly relevant to the future utilization of the Sarnia-Montreal pipeline.

With regard to light crude oil, all projections received from submittors confirm an outlook for

Table 3.1
Projected Supply of Light Crude Oil and Equivalent

	1990	1991	1992	1993	1994	1995	2000
Western Canadian Sedimentary Basin (WCSB)							
Conventional Light*	150.2	143.9	132.8	127.2	121.1	114.9	88.9
Synthetic	40.2	41.4	41.9	45.5	51.0	50.8	52.0
Total WCSB	190.4	185.3	174.7	172.7	172.1	165.7	140.9
Frontier**	0.1	0.1	2.7	2.7	2.7	2.7	31.5
Total Supply	**190.5**	**185.4**	**177.4**	**175.4**	**174.8**	**168.4**	**172.4**

* Includes available pentanes plus.
** Supply from East Coast Offshore and from Bent Horn in the Arctic Islands.

declining productive capacity in the near term, and a more stable or moderately increasing supply during the latter portion of the projection period if crude oil prices increase from current levels. The extent to which new projects, such as OSLO, contribute to supply over this period is largely dependent upon the crude oil price outlook.

The control case projection of heavy crude oil supply, which encompasses conventional heavy crude oil, bitumen and pentanes plus used as diluent, suggests that supply will increase gradually over the projection period from 76 000 cubic metres per day in 1990 to 87 000 per day in 2000. The outlook for heavy crude oil supply, however, is not considered to be a significant factor regarding the use of the Sarnia-Montreal pipeline.

It should be noted that projections of light and heavy crude oil availability are necessarily uncertain. Alternative price assumptions have a significant impact on projected crude oil supply. The supply outlook presented may also be somewhat conservative in that it is based on prudent assumptions regarding technological change. The range provided in the Board's projections and the submissions of interested parties is indicative of the uncertainty related to future domestic supply.

3.2 Petroleum Product Demand

Appendix VI shows petroleum product demands, by region. These preliminary forecasts were developed in connection with a staff analysis being completed for the 1991 update of the Board's biennial report "Canadian Energy Supply and Demand."

Most forecasts project modest growth in petroleum product demand. In our scenario, total demand for oil products is projected to increase from approximately 240 000 cubic metres per day in 1990 to 252 500 by 2000, an increase of some 12 500, or about five percent.

As is the case with other projections, there is a degree of uncertainty about future petroleum product demand which can have an impact on the overall supply demand picture.

3.3 Canadian Refinery Capacity and Feedstock Requirements

The major refinery centres in Canada are shown in Figure 3.1.

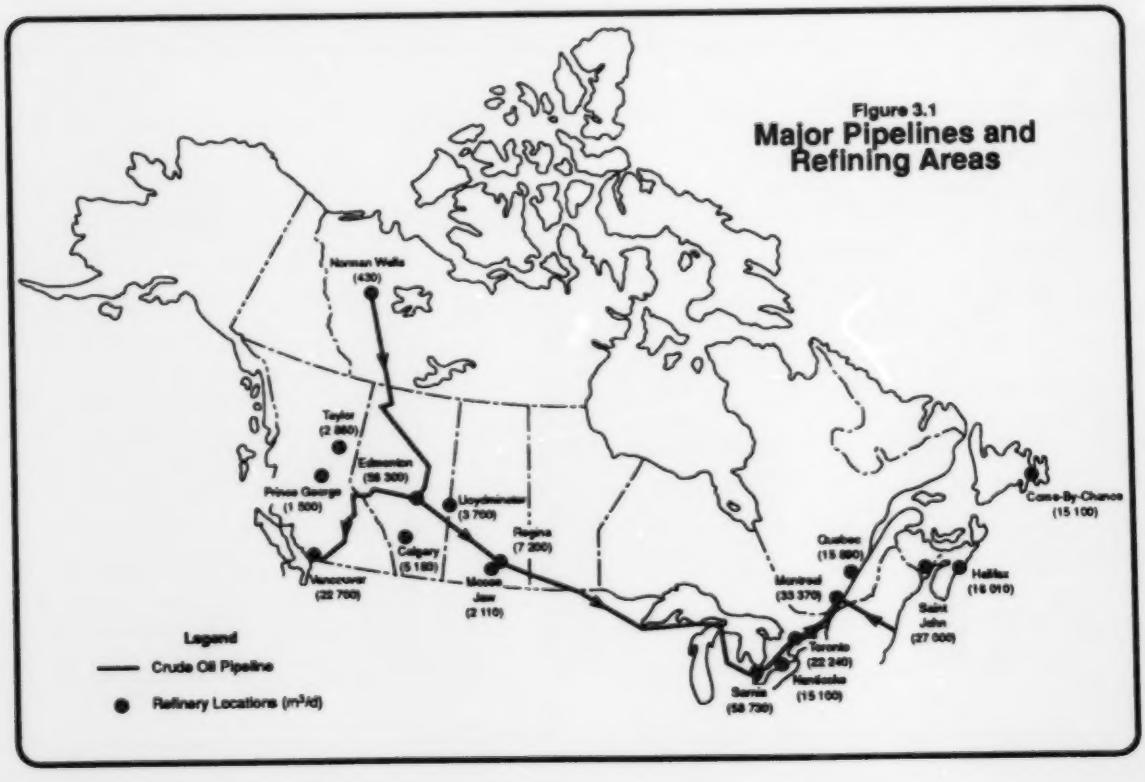


Figure 3.1
Major Pipelines and Refining Areas

In the past decade, Canadian refiners have faced a series of rapidly changing circumstances including highly volatile feedstock costs, reduced consumption of petroleum products, and an altered product demand slate. As well, there have been changes in product specifications. Canada's refining sector has been rationalized.

Thus, in 1980, the refining sector in Canada had a combined capacity of about 370 000 cubic metres per day. By the end of the 1980's, refinery capacity had declined by about 20 percent to approximately 305 000 cubic metres per day. Figure 3.2 sets out the size and utilization rates of the refining sector by region.

To assess the implications arising from trends in petroleum product consumption, product demands were converted to the corresponding requirements for refinery feedstocks. A summary of the analysis used to develop the estimates of refinery feedstock requirements is contained in Appendix VII. Based on this analysis feedstock requirements are projected to increase from 261 300 cubic metres per day in 1990 to 275 900 in 2000.

Since 1980, the refining industry has made improvements to its processing equipment to increase the production of light products such as gasoline, middle distillates (mainly diesel fuel), and jet fuels. The major challenges for refiners in the next few years will be to reduce sulphur levels in diesel fuel and to improve the quality of motor gasoline. These changes will be in response to continually more demanding product quality specifications, permitting a reduction in emissions of lead, sulphur oxides and nitrogen oxides. Substantial capital investment will be required. In this environment, it is unlikely that refiners would invest large amounts of capital to be able to process additional quantities of domestic heavy crude oil.

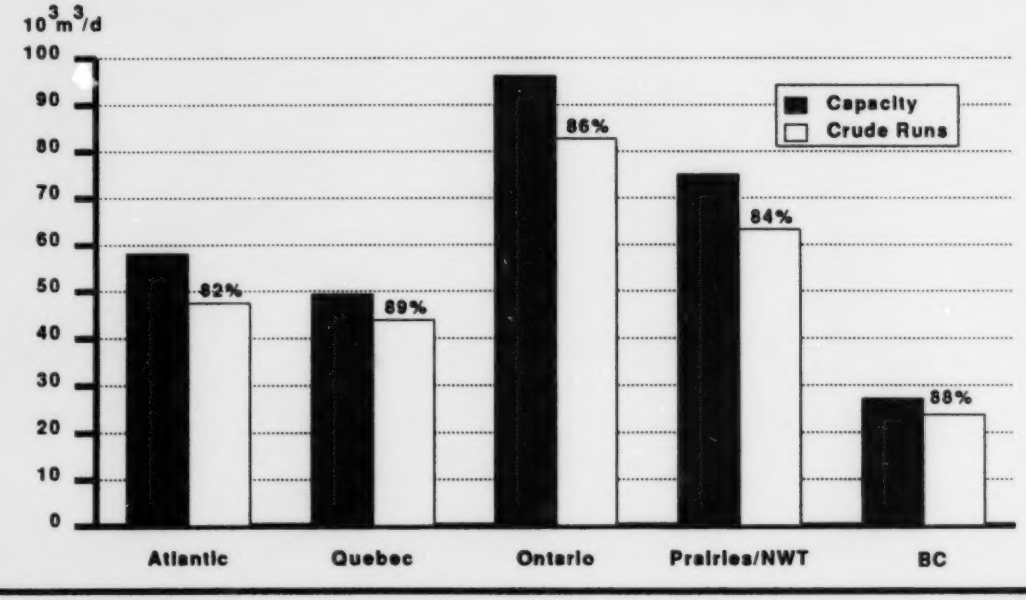
It is expected that virtually all of the growth in petroleum product requirements during the projection period can be met by increasing crude throughputs, resulting in higher capacity utilization.

3.4 Export Demand for Canadian Crude Oil

Most of the submissions were based on the assumption that available volumes of domestic light crude oil could be used to satisfy Canadian refinery feedstock requirements and that, if and as required, Canadian refiners could outbid American

Figure 3.2

Canadian Refinery Capacities, Crude Throughput and Utilization Rates: 1990



buyers for these supplies. These submittors did, however, mention that this was an assumption used to develop the supply and demand outlook and was not based on a refinery-by-refinery analysis of particular buyers' intentions. Some submittors held the view that, while it might be possible to attract supply from the export market to Ontario, this could make Ontario refiners uncompetitive in the products market they serve.

Interested parties observed that the future level of Canadian light crude oil exports would, in part, depend on supply and demand in PADD II, and the logistics of supplying this area. There was a range of opinions about the need for additional supplies in this market. Related to this was the matter of transportation costs from the U.S. Gulf. It was generally agreed that existing transportation systems are essentially fully utilized and that provision of additional pipeline capacity would result in higher tolls.

In the Board's view, current patterns for the disposition of Canadian crude oil can be expected to continue. In particular, it is conceivable that market forces could result in sustained levels of light crude exports of between 20 000 and 30 000 cubic metres per day. A level of 20 000 cubic metres per day has been used for developing the supply and demand outlook in section 3.5. (For comparison, light crude oil exports were about 45 000 cubic metres per day in 1990.)

This conclusion was based on a refinery-by-refinery assessment of the likely crude oil acquisition intentions of U.S. buyers and of the capability of Canadian refiners, particularly in Ontario, to process light sour and synthetic crude oils.

3.5 Supply and Demand Balance of Light Crude Oil

Refineries in Canada generally use light crude oil while the bulk of Canadian heavy crude oil production is exported. Within the range of light crude oils, significant quality differences exist which can influence the regional demand for these oils.

The demand for domestic heavy crude oil is seasonal, depending mainly on the requirement for asphalt. The processing of domestic heavy crude oil for the manufacture of refined products other than asphalt is currently limited by available refinery facilities and no significant change to this pattern is expected. Because of this, the discussion that follows will concentrate on light crude oil. (Appendix VIII, however, sets out the supply and demand balance for domestic heavy crude oil.)

Submittors held differing views about the outlook for supply and demand in Canada and, in particular, about when imported light crude oil would be required in Ontario.

Most producers and provinces in eastern Canada, including Quebec, thought that there would be sufficient light crude oil supply from western Canada to satisfy Ontario and a portion of Quebec's requirements through the Sarnia-Montreal pipeline, at least until the mid-1990's. This group held that, while a market-oriented approach should be used to determine the future use of the Sarnia-Montreal line, premature reversal should be avoided.

Refiners held a variety of opinions. One Ontario refiner stated that there would be sufficient supplies of domestic crude oil to supply the province until the late 1990's, given some reduction in exports. Two others held views similar to those of the producers and provinces, i.e. that imported oil would not be needed in Ontario until the mid-1990's. The two remaining Ontario refiners thought that imported oil would be required in the near term and that the regulatory process to consider reversal of the Sarnia-Montreal pipeline should begin as soon as possible.

Ontario stated that its refining industry was designed to process light sweet crude and that, because of depressed profits and the need to invest large amounts of capital now and in the future to meet environmental requirements, it was unlikely that additional investments would be made to process domestic heavy crude oil. Against this background, the province concluded that, with declining supplies from western Canada, Ontario would require overseas supplies and at the best possible price.

IPL thought that Ontario refiners would begin to require imports by about the mid-1990's but observed that this need could arise sooner, or later, depending both on the volume of light crude oil supplies from western Canada and the level of exports.

Appendix IX shows the supply and disposition of domestic light crude oil and equivalent. Like the product demand analysis, it reflects work done for the Board's 1991 "Canadian Energy Supply and Demand" update.

In 1990, available domestic supply was nearly 195 000 cubic metres per day, of which approximately 150 000, or about 75 percent, was used in Canada. The balance of approximately 45 000 cubic metres per day was exported, mainly to PADD II.

It was assumed that through to 2000, western Canadian light crude oil will be used first to satisfy refinery demand in western Canada plus a minimum export level of 20 000 cubic metres per day. The balance would then be available to Ontario refiners. In addition, it was assumed that most of the eastern Canadian offshore production would be exported. It was further assumed that the Sarnia-Montreal pipeline would be deactivated in mid-1991.

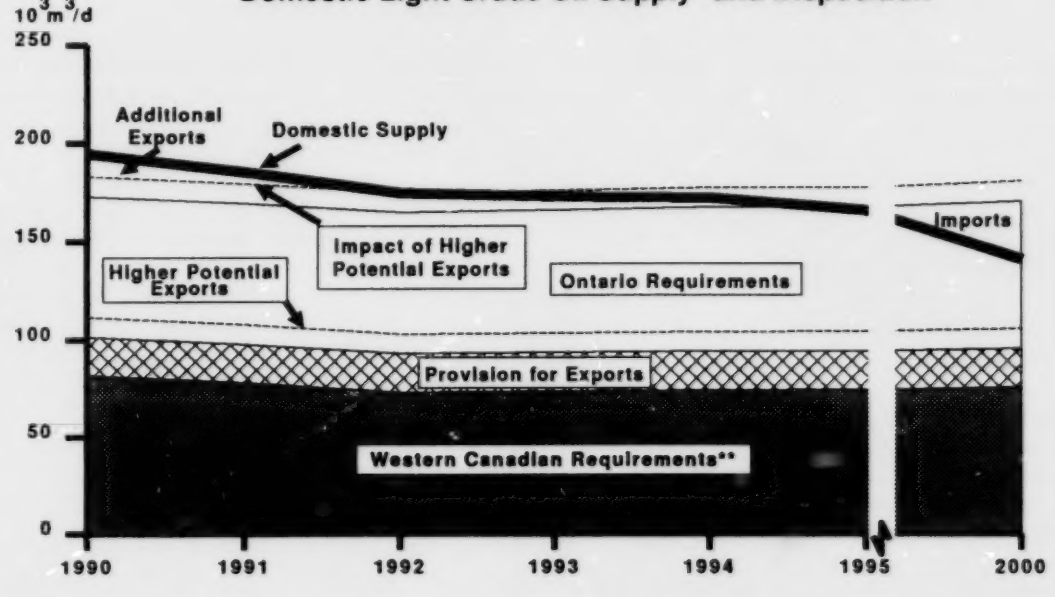
The use of domestic light crude oil in Canada is expected to decline from the approximately 150 000 cubic metres per day used in 1990 to about 121 000 by 2000, mainly because of the declining production of light crude oil from western Canada.

Exports may fall from about 45 000 cubic metres per day in 1990 to approximately 23 000 in 1995, consisting of the assumed minimum exports of 20 000 from western Canada and the small volume of east coast production. Exports increase to more than 50 000 cubic metres per day in 2000, reflecting the base 20 000 from western Canada and rising east coast production, mainly Hibernia.

Appendix X contains details of light crude oil requirements and domestic supply for Ontario for the period to 2000. Figure 3.3 summarizes this analysis.

It has been assumed that Ontario refiners will generally continue to process light crude oil,

Figure 3.3
Domestic Light Crude Oil Supply* and Disposition



* excludes East Coast production
** includes small volume of domestic light feedstock for Quebec in 1990 and 1991

mainly sweet, to meet product requirements. Other alternatives, such as refining a substantially higher proportion of heavy crude oil or relying on imports of significant quantities of products, were assumed to be less viable.

From a level of about 71 000 cubic metres per day in 1990, Ontario's light crude oil needs are expected to grow to approximately 75 000 by 2000. As a consequence of the declining availability of domestic feedstocks throughout the review period, Ontario refiners will, in the Board's analysis, likely have to consider options, perhaps later this year, to arrange for imported supplies beginning in about 1993 or '94, depending on the availability of particular grades of light crude. Dependence on foreign feedstocks is projected to be about 29 000 cubic metres per day by 2000, when imports could represent nearly 40 percent of Ontario's light crude oil requirements.

The major factors influencing the timing of the need for imported feedstock supplies in Ontario include the growth in petroleum product demand, the availability of domestic light crude oils and the level of continuing light feedstock exports. If, for example, these exports dropped only to 30 000 cubic metres per day, instead of 20 000, imports could be required as early as 1992. On the other hand, if exports fell to 10 000 cubic metres per day, imports might not be required until perhaps 1996 or 1997.

The precise timing of the need for imported supplies in Ontario will depend on industry's assessment of various strategic, commercial and operational considerations.

Most importantly, Ontario refiners, particularly those less able to cover their crude oil requirements from integrated Canadian operations, will likely want to minimize the risk of encountering a shortfall of economically-priced crude oil. Some companies in the industry can therefore be expected to adopt a somewhat conservative assessment of the short-term outlook for domestic supply, and perhaps to plan against the possibility of such other events as unexpectedly strong growth in petroleum product demand or higher light crude oil export levels.

Ontario refiners will also determine not only their requirements for crude oil in total, but also their needs for specific grades of feedstock used in the manufacture of specialty products such as lubricants. As well, it is not clear at this stage whether new refinery investments would be required to process the incremental supplies of synthetic crude oil which are expected to be available later in the 1990's. Depending on the quality of these new supplies, some investment may be required. Alternatively, these feedstocks could be exported. Finally, interested parties cited seasonal demand patterns as a factor that could result in the need for imported crude oil earlier than would be evident from an analysis of annual supply and demand estimates. While the Board did not do a detailed seasonal demand analysis, it considers that this factor could lead Ontario refiners to have earlier, rather than later, recourse to overseas crude supply.

Chapter 4

Factors Affecting Changes to Supply Patterns

Recent changes in North American crude oil supply patterns have resulted in changes in the basis on which prices have been set for Canadian light crude oil relative to competing grades. These changes, in addition to the supply and demand circumstances described in Chapter 3, have resulted in a re-evaluation of Montreal and Ontario refiners' choices of feedstock sources.

4.1 U.S. Crude Oil Supply

Crude oil and equivalent production in the lower-48 states has been declining for a decade. Production from the Prudhoe Bay field in Alaska may have also peaked, but the state's production is being maintained through the coming on stream of new producing fields. In 1990, aggregate production in the United States declined for the fifth consecutive year, and has reached the lowest level since 1961. There is widespread agreement that this decline will continue. As a result, more and more overseas oil will be needed to balance supply and demand, particularly in PADD II, where pipeline reconfiguration has already begun in order to accommodate increasing volumes of imports. As in Canada, much of the decline in U.S. crude oil supply has been in light sweet grades. The decline in availability of crude oil in inland North America is causing refiners to seek alternative supplies and has changed pricing patterns affecting refiners' choices.

4.2 North American Crude Oil Price Relationships

Canadian crude oil prices are driven by those of competing crudes. The price of Canadian sweet crude has usually been determined relative to the price of West Texas Intermediate ("WTI") delivered to Chicago, the market where the two streams directly compete.

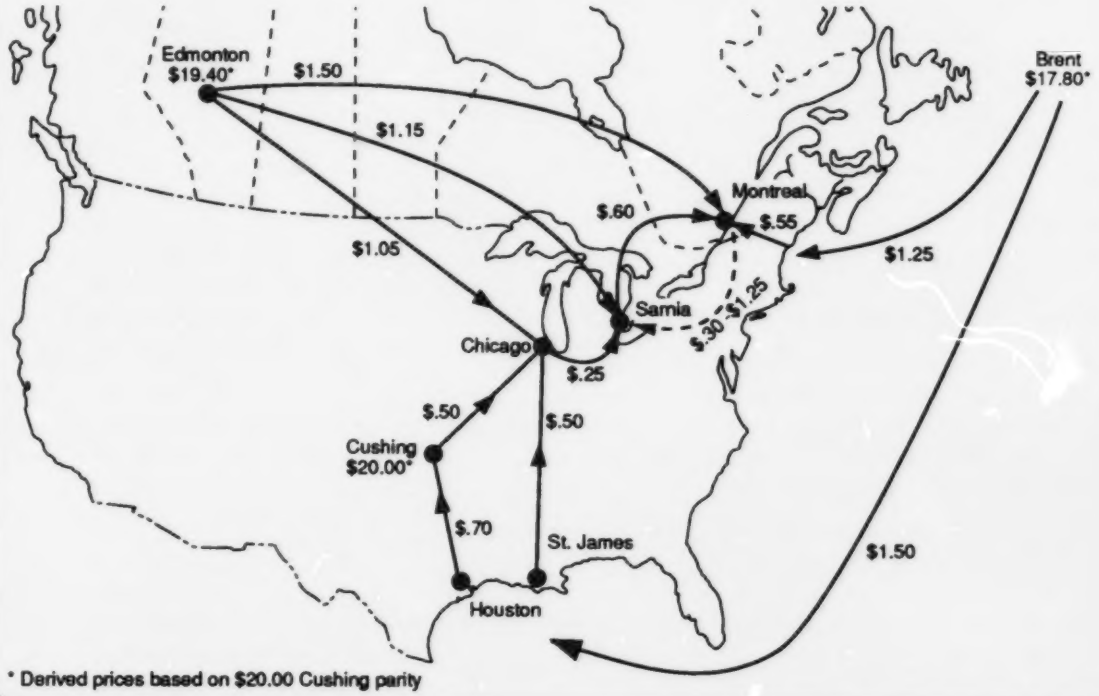
Until late 1987, WTI was priced to compete with comparable North Sea crude oil (Brent) at refineries in the U.S. Gulf, making it the parity pricing point for these crude types. Concurrently, IPL capacity constraints were causing uncertainty over the scheduling of deliveries of Canadian sweet crudes. For these reasons, American refiners tended to view Canadian sweet crudes as "swing barrels", and accordingly discounted them against WTI. This meant that, at Montreal, Canadian light sweet crude oils were either competitive with, or enjoyed a price advantage over comparable overseas oils which reached Montreal via Portland, Maine. At that time, there was a two-tier seasonal toll on the Portland-Montreal pipeline. Consequently, in winter, Canadian light sweet crude oils were cheaper than overseas oils at Montreal, but in summer, when the lower Portland pipeline rate prevailed, their delivered costs were similar.

With the decline in availability of WTI, the American mid-west refiners began bidding up its price, thereby shifting the parity point away from the U.S. Gulf to Chicago. WTI was then at par with North Sea oil delivered to Chicago by the most economic pipeline from the U.S. Gulf. As would be expected, the increase in the price of WTI pushed up the relative price of similar Canadian crude oils. This resulted in Canadian crude oils becoming uncompetitive in Montreal compared to North Sea grades during the summer months.

The trend towards a higher relative price for WTI is likely to continue. As its production declines, the demand for imported crude oil in PADD II increases and less economic pipeline routes have to be followed, further increasing the value of WTI. This increased price of crude oil at Chicago, where similar Canadian feedstocks compete, benefits Canadian sweet crude producers but makes them less competitive relative to overseas oil at Montreal.

Figure 4.1 illustrates the transportation costs applicable to Brent crude oil, WTI and Canadian sweet crude from their supply sources to relevant North American markets. Although these costs

Figure 4.1
Transportation Costs For Brent, WTI and Sweet Mixed Blend
(U.S. $/Barrel)



may not be applicable in all instances for all shippers, they are representative of the apparent costs to a refiner that is not co-incidentally an equity owner in one of the particular transportation systems. [Tables 5.1 and 5.2 (for which detailed background is provided in Appendices XI and XII) have been derived using these transportation costs and assuming that the price of WTI and Brent would be at a parity price of $U.S. 20.00 per barrel at Cushing, Oklahoma. This implies an F.O.B. price of about $U.S. 17.80 for Brent at Sullom Voe, its loading location in Scotland.]

Figure 4.2, provided by Shell, illustrates the price relationship between Canadian sweet crude oil and North Sea crude oil (Brent) in Montreal and how it has varied over the past few years, and shows that overseas crude is becoming more competitive. The seasonal fluctuations are also illustrated. (Our analysis, although it does not agree in detail with Shell's, led us to the same conclusion). Reflecting discussions with industry, we have assumed Cushing parity prices for WTI/North Sea Brent in the analysis of specific markets in Chapter 5. This assumption, although not perfect, is, for the most part, the basis on which refiners are now making crude oil acquisition decisions. Given that an increase in the supply of U.S. light crude oil is not expected, this pricing relationship is likely to persist.

In summary, the decline in the supply of conventional light crude oil in Canada and the U.S. has led to imports of incremental overseas volumes into PADD II. This has strained pipeline transportation systems in the U.S., led to reconfigurations resulting in higher tolls at the margin and caused an increase in the prices of WTI and of similar Canadian crude oils. Consequently, the price of Canadian light sweet crude oil delivered to Montreal has become uncompetitive with that of overseas oil such as North Sea Brent.

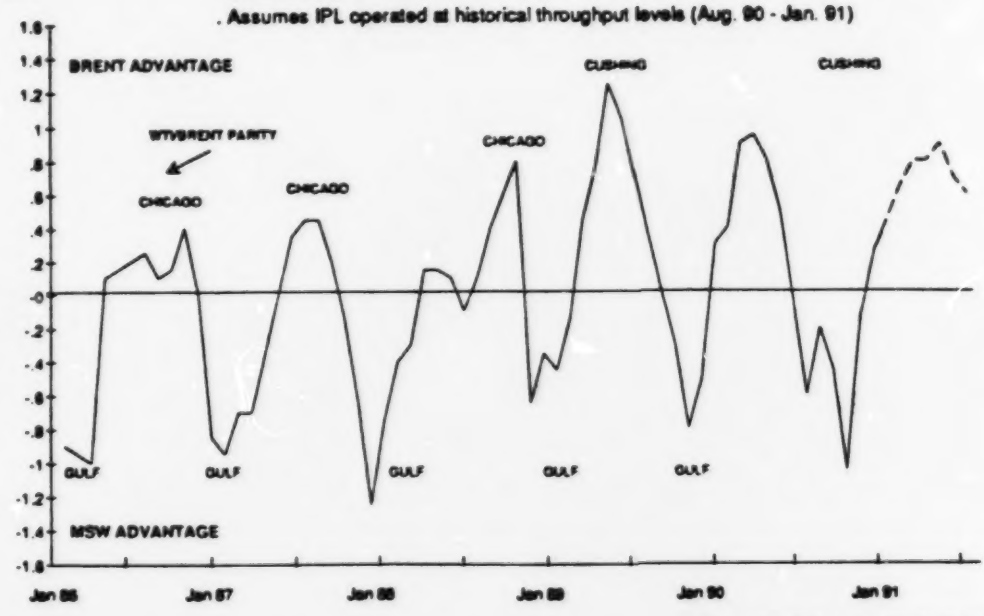
Figure 4.2

MSW vs Brent Advantage @ Montreal

US $/B

. Outlook as of Jan. 1991

. Assumes IPL operated at historical throughput levels (Aug. 90 - Jan. 91)



Source: Shell Canada Products Ltd.

Chapter 5

Supply Options for Eastern Canadian Refiners

Eastern Canadian markets comprise three regions: Atlantic Canada, Quebec and Ontario. Each region has developed its own distinct petroleum supply patterns based on existing supply economics and transportation logistics.

Atlantic Canada imports its refinery feedstock requirements from overseas. This sourcing has served the region well, both in terms of cost and accessibility.

Quebec has two refining centres - Quebec City and Montreal. Quebec City, like Atlantic Canada, imports its total requirements directly from overseas. Because the supply patterns for both Atlantic Canada and Quebec City are similar, they have been grouped together for the analysis in this section. Montreal, until recently, had been relying equally on overseas imports and deliveries from western Canada through the Sarnia-Montreal pipeline, but with changing supply economics, it will soon source its feedstock requirements entirely from imports.

Ontario also has two refining centres - Sarnia and Toronto; the supply patterns for both are similar. Ontario refiners have depended, in the past, almost entirely on western Canada for their total feedstock requirements. However, in recent years, they have been importing marginal volumes from the United States and from overseas, via the U.S. Gulf and connecting pipeline systems.

The continued decline in the supply of domestic light crude oils will require eastern Canadian refiners, more particularly those in Ontario and Montreal, to compete to a greater extent with American refiners in the Northern Tier, and, at the same time, to identify and draw on other supply sources. Feedstock requirements for refineries in British Columbia and the Prairies will continue to be met from Canadian production. As indicated in section 3.5, Ontario will require significant volumes of overseas crude oil by 2000. From mid-1991, Montreal refiners are likely to be wholly dependent on overseas crude oil. The alternatives for the future operation of the Sarnia-Montreal extension are deactivation, west to east flow, and east to west flow. The following sections examine how the various regions in eastern Canada will be affected by each of these alternatives.

5.1 Atlantic and Quebec City

The geographical location of Atlantic Canada and Quebec City makes water-borne imports the only viable source of supply for the region pending possible large-scale development of eastern Canadian, including eastern arctic, oil reserves.

In past emergency situations, western Canadian oil has been shipped out of Vancouver, and through the Panama Canal to refineries on the eastern seaboard. This is an uneconomic movement. If additional western Canadian oil could be made available in a possible future international emergency, it could better be exported by pipeline to the U.S. in exchange for additional imports to Atlantic Canada and Quebec. If the Sarnia-Montreal extension were to be idled, or the flow reversed, then transshipment of domestic feedstocks at Montreal to refineries east of Montreal would not be available. But in any event, the exchange option is a preferable means of securing additional emergency oil supply for that region.

5.2 Montreal

From its establishment about the time of the First World War, the Montreal refining industry depended on imported oil. For the period from mid-1976, Canadian crude has been available by pipeline. During this time, Montreal refiners have continuously assessed the economics of the two dominant supply options: western Canadian feedstocks supplied through IPL, and overseas imports through the Portland pipeline. In the era of controlled prices it was generally attractive to acquire Canadian feedstocks.

Table 5.1

Representative Light Sweet Crude Oil Supply Costs at Montreal
($U.S. per barrel)

	Canadian	WTI	Brent via		
			U.S. Gulf-Capline	U.S. Gulf-Arco/Texaco Pipeline	Portland/Montreal Pipeline
Delivered Cost at Montreal	20.90	21.10	20.40*	21.10	19.60

* While Capline appears to be a desirable option, over the longer term the system is expected to be at capacity, precluding incremental use of this line.
Source: Appendix XI

Refinery rationalization in Montreal during the 1980's saw three of the five plants shut down, effectively reducing throughput on the Montreal extension. Since then, throughput has continued to decline. In recent years, the decline in the production of domestic conventional light crude oil and the attractive economics of imports led Montreal refiners by March 1991 to forego domestic supplies. Even during the 1990-91 Iraq-Kuwait crisis, the throughputs on IPL's Montreal extension continued to decline. At the time of writing, there appears to be little economic incentive to use the line. Its deactivation or reversal would leave Montreal refineries wholly dependent on overseas imports, as indeed they were prior to mid-1976.

The price competitiveness of each of the supply and transportation options available to Montreal refiners is set out in Table 5.1. North Sea Brent, representative of overseas supplies, delivered via the Portland-Montreal pipeline system appears to be by far the most economic feedstock for Montreal refiners. Alternative sources would increase refiners' acquisition costs in the order of $U.S. 1.00 per barrel based on Cushing parity.

5.3 Ontario

Ontario refineries have, since 1951, depended on western Canadian crude oil. However, marginal quantities of U.S. domestic and overseas feedstocks have recently been imported.

Changes in crude oil availability from different sources have brought about changes in the use made of the American pipeline systems. Thus, some of the smaller pipelines which had been moving U.S. domestic crude to refineries in the U.S. Gulf have been reversed. They now bring imported oil northwards, supplementing the principal northward-flowing pipelines, such as the Capline system which, from time to time, has reached capacity operation.

While sufficient western Canadian light crude oil is likely to be available to satisfy Ontario requirements through 1993 or '94, the continued declining trend in conventional light crude oil production will prompt Ontario refiners to develop alternative supply sources.

While Ontario does have access to U.S. domestic oil and to overseas feedstocks through the U.S. Gulf, its refiners have made only limited use of this option because of the high transportation costs, difficulty in obtaining secure pipeline access and crude quality degradation as a result of transshipment between pipelines.

In discussions with industry, it was generally accepted that reversal of the flow in the Sarnia-Montreal extension was probably the preferred solution for Ontario refiners' long-term supplemental crude oil requirements. Reversal would provide them with access to reliable alternatives. However, there was no consensus as to the timing of the reversal.

The following Table 5.2 summarizes the landed cost of light sweet crude oil for the various supply

Table 5.2

Representative Light Sweet Crude Oil Supply Costs at Sarnia

($U.S. per barrel)

	Canadian	WTI	U.S. Gulf-Capline*	Brent via U.S. Gulf-Arco/Texaco Pipeline	Portland Sarnia-MontrealReversal**
Delivered Cost at Sarnia	20.55	20.75	20.05	20.75	19.90 - 20.85

* While Capline appears to be a desirable option, over the longer term the system is expected to be at capacity, precluding incremental use of this line.

** Reflects range of tolls provided by IPL in its submission

Source: Appendix XI

and transportation options for refiners in the Sarnia area. Based on IPL's submission and data provided, the most favourable economics occur when foreign feedstocks are imported on a reversed Montreal extension at a high rate of throughput. At lower rates, co-incident in IPL's case with higher tolls, this option might not appear to be as attractive. However, given reduced supplies of Canadian and American domestic light crude oils and pipeline capacity constraints in the United States, a reversed Sarnia-Montreal pipeline could, over time, become the most desirable supplemental source of feedstocks for Ontario.

In summary, water-borne imports continue to remain the only viable source of supply for Atlantic Canada and Quebec City. Similarly, deactivation or reversal of the Sarnia-Montreal line would leave Montreal refiners wholly dependent on overseas imports. Ontario refiners, as a result of declining supplies of domestic conventional light crude oil, will have to develop alternative supply sources. A reversal of the Sarnia-Montreal pipeline is an option which, depending on toll treatment, could provide them with the most economic access to overseas crude oil.

Chapter 6

Security of Supply

Regions that depend on oil, particularly imported oil, for a significant portion of their energy requirements are vulnerable to supply disruptions that can have negative consequences for their economic well-being. Security of oil supply is therefore a major concern for such markets. If there were to be a supply disruption, market forces would ensure that, over the long run, prices would adjust to encourage additional oil production, energy conservation, supply diversification and the development of alternative fuels. In the short run, however, there may be physical supply disruptions or price shocks. Security of supply relates to moderating these short run impacts of an oil emergency by ensuring that sufficient oil supplies are available and that the economy is protected from sudden sharp increases in the price of oil.

The provinces of New Brunswick, Nova Scotia and Prince Edward Island made strong representations that tactical and strategic storage be put in place for use in an emergency; these provinces are much more dependent on oil for heating and electricity generation than is the rest of Canada and security of oil supply is understandably a greater concern for them.

Quebec indicated that it did not wish to rely on the IEA or on Canada's position as a net exporter for security of supply. The province argued that without a direct link to western Canada, it was in the same position as other importing countries and therefore needed strategic stocks to cover 90 days' import or equivalent security measures. Strategic stocks were considered necessary despite the possibility of exchanges. Quebec did not wish to take the risk of delays in its ability to access western Canadian oil resulting from regulatory action or re-testing the line.

Ontario was concerned not only with the declining supply of conventional light crude oil in Canada but also with the long transit times and high cost of transportation for overseas oil through the U.S. Gulf and mid-west pipeline systems. According to Ontario, a reversed Sarnia-Montreal pipeline would provide the province with access to more competitively priced and secure supply.

EMR's 1987 study "Energy Security in Canada" discussed various options for meeting emergency needs in Eastern Canada. IPL was identified as the primary mode within Canada for transporting domestic oil to the region. EMR's study also addressed the possibility that market forces could dictate deactivation or reversal of the Sarnia-Montreal pipeline but noted that, if it could be quickly put back into west to east service in an emergency, reversal would not impair security of supply. The study also identified alternative transportation modes to the Sarnia-Montreal pipeline, namely, shipments via the St. Lawrence Seaway, by tanker from the west coast to Atlantic Canada and Quebec via the Panama Canal, and swaps with the United States.

If the Sarnia-Montreal pipeline were to be maintained in west to east service or modified for bi-directional flow, there would be no change in its contribution to supply security. If the pipeline were to be reversed for east to west flow, concurrent installation of re-reversal facilities would cost only about an additional $2 million. With such facilities it would take about two weeks to re-reverse the extension in an emergency.

If the pipeline were deactivated, however, re-filling it would take at least four weeks and would require 2.3 million barrels of linefill which may not be readily available in an emergency. Moreover, according to current regulations, if the line has been deactivated for 12 months or more it must be retested prior to reactivation. This could take four months and cost approximately $4 million.

The Sarnia-Montreal pipeline is therefore less useful from a security of supply standpoint if it is purged of oil and deactivated than if it is reversed and used to flow east to west. The question arises, should the government prevent deactivation and

ensure that the pipeline is available to flow west to east at short notice by either buying or renting linefill.

The Board notes, in this connection, that no parties expressed interest in paying for linefill in order to provide security of supply. A decision by the federal government to seek to enhance energy security through actions respecting the pipeline presumably depends on whether the benefits to Canada of such actions are likely to exceed their costs and whether they would be superior to those offered by alternative courses of action. Assessment of the magnitude of the benefits will be affected by the expected frequency, size and duration of the disruptions; the assumed effectiveness of international and national mitigative measures; and the likely remaining impacts of disruptions on the social and economic well-being of Canadians. As explained in the EMR paper, it is extremely difficult to assess these benefits. The nature and timing of future world oil crises are impossible to predict. The impact of an oil shortage on Canadians is also very difficult to quantify, particularly since this country has never experienced one.

The Board also notes that since the 1979-80 oil crisis, Canada's import supplies have become more geographically diversified outside of the Middle East and disruptions overseas have had proportionately smaller effects on oil supply and price than those of 1973-74 and 1979-80. Moreover, the vulnerability of import-dependent regions of Canada appears to be reduced today compared to the 1970's, by virtue of the presence overseas of surplus oil-producing capacity; the demonstrated flexibility of the international oil industry; the ability of free energy markets to adjust to changes in supply, demand and price; and the existence of comprehensive national and international oil emergency measures. Although it is difficult to anticipate future world oil developments, these factors suggest that the security of supply considerations, which originally led to the construction of the Sarnia-Montreal pipeline, have diminished.

From the standpoint of domestic supply, there are limitations as to what can be done to direct Canadian oil through the Sarnia-Montreal pipeline. Crude oil movements are determined by the workings of the marketplace or potentially under provisions of the Free Trade Agreement. In the event of a disruption, depending on Canada's obligations and rights under the IEA's International Energy Program, and depending on the overall availability of oil from western Canada, the usefulness of the line to supplement supplies to eastern Canadian markets may be limited.

Chapter 7

Impacts on Markets and Prices

Factors such as the abundance of middle east sour crude oils in the U.S. Gulf have generally resulted in quality differentials which are wider for Canadian than for U.S. production. Canadian differentials widened further during 1990 and early 1991 because of seasonal factors; the global oil price impacts of the Iraq-Kuwait crisis; and the loss of market at Montreal for Canadian sour crude oils. This widening has tended to improve the economics of continuing sour crude shipments to Montreal. Some submittors felt, however, that the widening in the light-sour price differentials would be significantly reduced by summer 1991, while others felt that differentials would by then return to historical levels.

Concern was expressed by some submittors at an early reversal of the Sarnia-Montreal extension. It was felt that premature reversal could have an adverse impact on the wellhead price of Canadian crude by increasing price competition of foreign oil in Ontario; reducing the established market share for Canadian crude; and forcing Canadian producers into less attractive U.S. markets. Even the Ontario refiners who were anxious to see the line reversed as quickly as possible indicated that there could be an impact in the short-term, until markets adjusted to the shifts in trade patterns. Others, however, supported the idea that it would be difficult to quantify the impact of reversal because it is impossible now to assess the overall market environment in which the new trade patterns would have to be established.

The issue of IPL toll design as it affects the Sarnia-Montreal line was of concern to many interested parties. Several submitted that tolls for the pipeline should be cost-based. Particularly with respect to reversal, producers supported stand-alone tolls and opposed the concept of continuing integrated tolls: there was concern that use of a reversed Sarnia-Montreal line should not be "subsidized" by users of the Older System. Moreover, several parties suggested that, if the line is reversed, it should be recapitalized for toll purposes to offset the effect of its "accelerated" depreciation rate of 5 percent. Parties taking this position felt that, since the delivery of foreign oil into Ontario could adversely affect prices and markets for domestic oil, there should be no element of "subsidy" in the tolling of the reversed line.

IPL submitted that the integrated method of toll design should continue if the Montreal extension is maintained for crude oil service, regardless of its operation (continued west to east flow, deactivation, or reversal). IPL did not provide detailed justification for this position, stating that toll methodology should be examined in the Company's next Class 3 toll hearing.

The Board agrees that toll design, including rate base treatment, can have significant implications on the economics of each of the options for the Montreal extension and potentially on competitive prices under certain conditions. Views on these matters were not explored in detail for this study and it is appropriate that they be brought forward by IPL or interested parties at future toll proceedings.

Chapter 8

Options for Continued West to East Flow

Although interested parties cited a number of options by which the flow in the pipeline could remain from west to east, most were of the view that market forces alone should be left to determine the use of the pipeline.

The options identified included the purchase of the linefill by the federal government or by IPL; joint arrangements by producers and refiners to share linefill costs; and incentive pipeline tariffs. The option having the widest support was for the government or IPL to own the linefill. It should be noted in this regard that submittors unanimously preferred that industry ***not*** bear the costs of such actions, if they were taken to enhance security of supply.

Linefill Ownership

Currently, the linefill in the Sarnia-Montreal pipeline is owned by the shippers. The long transit time at low throughputs has resulted in high inventory carrying costs per unit of throughput, as well as difficulties in scheduling deliveries of specific crude oil batches to Montreal refineries.

If the linefill were purchased by either IPL or the federal government, and if a common stream could be found acceptable to both Montreal refiners, this cost component could be eliminated from the crude oil pricing equation: for economic purposes, pipeline inputs at Sarnia would be translated directly into deliveries into Montreal. At current oil prices the cost of the 368 000 cubic metres (2.3 million barrels) of linefill is estimated to be about $50 million, with a carrying cost of approximately $0.5 million per month. At throughput rates of 15 000 cubic metres per day, the average rate during 1989, the unit carrying cost amounts to about $1.00 per cubic metre or $0.15 per barrel. At lower throughputs, the costs are proportionally higher.

IPL indicated that it would consider buying the linefill, with the cost of the purchase being charged to general system users. It was IPL's position that it would not be inappropriate to charge this cost to all system shippers since maintaining access to the Montreal market for heavy and light sour crudes would benefit western Canadian producers. The purchase of the linefill could have an impact on Older System tolls of about $0.20 per cubic metre or $0.03 per barrel.

Several companies said that they would be willing to consider innovative financing so that the linefill costs may be shared between producers and refiners. There was, however, no consensus on how such arrangements might be structured. When this matter was explored in more detail, several parties, including those companies which would normally hold the linefill, suggested that the co-operative arrangements contemplated would not likely be achievable in practice, given the divergence of corporate interests, and the fact that these interests are often in competition with one another.

Other options cited that would support continued operation of the line in a west to east mode included incentive tolls. IPL indicated that consideration could be given to varying the tolls from time to time to reflect market conditions. This was suggested as a means to help maximize volumes moved through the line.

Shipments in a west to east direction could be encouraged through ownership of the linefill by either the government or IPL, or possibly some form of incentive tolls. The indication from Montreal refiners, however, was that only heavy and light sour crudes could be expected to benefit from such a proposal. The capacity to refine light sour crudes in Montreal is limited to perhaps 3 000 to 5 000 cubic metres per day; shipments of heavy crude grades would be limited mainly to seasonal demand for the manufacture of asphalt, or as an export outlet for volumes that could not otherwise be sold.

A toll ruling favourable to IPL would have to be obtained in order for IPL to include linefill costs in its cost of service. It is not likely that IPL would pursue such a proposal unless it had some support from producers or refiners. The possibility also exists for the government to support west to east shipments by purchasing the linefill outright, or by making an arrangement for either IPL or a shipper such as Shell to hold the linefill on its behalf. The major advantages of such a decision would be to allow producers access to Montreal markets, and therefore help clear the market of any excess light sour and heavy crude oils. The disadvantages of such action is that it would cost the taxpayer about $0.5 million per month and, perhaps more importantly, it could bias industry decisions on the most economic use of the line.

Several parties indicated that, if the line were shut down, they would argue that the integrated toll methodology which is currently being applied should be discontinued. Others opposed such a tolling change. Parties were reminded that an NEB toll proceeding is the only forum in which evidence and argument on appropriate IPL toll methodologies can be presented, tested and a decision rendered.

Chapter 9

Pipeline Engineering and Environmental Considerations

A detailed discussion of the pipeline engineering and environmental considerations relative to deactivation, reversal and bi-directional flow is provided in Appendix XIII.

Two alternatives are available for the deactivation of the pipeline. The first involves filling the line with crude oil treated with corrosion inhibitors (at a one-time cost for inhibitors of $200,000), and the second involves purging the line and filling it with nitrogen (one-time cost of $1.8 million). Pressure testing of the pipeline is required if it is deactivated for a period of 12 months or more. A retesting program would take up to four months and cost approximately $4 million.

In order to reverse the operation of the pipeline to deliver foreign crude from Montreal to Sarnia, additional facilities are required. A first phase reversal (for a capacity up to 45 500 cubic metres per day) would require the construction of a new initiating station and associated piping, together with new or leased break-out storage facilities at Montreal. It would also require modifications at the existing pump stations. The total cost to IPL would be in the order of $35 million, including $2 million for facilities providing for re-reversal. Should IPL be unable to secure tankage in Montreal, the total cost would increase by about $28 million. To meet the requirements of Montreal refineries as well as east to west flow into Ontario, the capacity of the Portland-Montreal pipeline would also be expanded at a cost of about $2 million.

A second phase reversal (up to 68 000 cubic metres per day) would require the construction of three new pump stations, and the construction of additional storage and piping at Montreal and Sarnia. This would cost some $65 to $95 million in addition to the first-phase costs. In this case the capacity of the Portland-Montreal pipeline would require further expansion at a cost of about $9 million.

The facilities for re-reversal would allow seasonal-type changes in mode of operation with no significant difficulty. However, a very frequent change in direction (yo-yo operation) could not be handled without the addition of the "second phase reversal" facilities and a large volume of tankage at a cost in the order of $200 million. This option would appear impractical.

Both the deactivation and the reversal options are feasible from an engineering and environmental standpoint. They would be considered in more detail during the review of the required applications to the Board.

Chapter 10

Regulatory Process

The continued west to east operation of the Montreal extension would not require any particular action involving the Board. Neither would the Board need to become involved should IPL deliver the crude oil that is currently in the pipeline and deactivate the line for a short term, aside from ruling on any tolling issues that might arise.

However, section 53 of the *Onshore Pipeline Regulations* provides that once IPL proposes to deactivate the pipeline for a period of 12 months or more, it must apply to the Board for approval of the deactivation. In such an application, the company would have to demonstrate that the deactivation provides for a level of safety at least equivalent to the level generally provided by CSA standards and that the deactivation is in the public interest. The Board would likely solicit written comments from interested parties when such an application is considered.

The regulations also provide that, where a pipeline has been deactivated for 12 months or more, a company shall not reactivate the pipeline unless it has applied for, and received, the Board's approval to do so, and has retested the pipeline in accordance with the specific procedures set out in the regulations.

The Certificate of Public Convenience and Necessity (OC-30) under which the pipeline was built contemplates the possibility of the operation of the line in an east to west direction. Consequently, a decision by IPL to reverse the flow of the extension would not require an amendment to the certificate. Certain relatively minor construction would have to be made, however, requiring an application for an order pursuant to section 58 of the NEB Act. IPL has indicated that it would want a ruling from the Board on the toll methodology that would be applicable to a reversed line before deciding whether to apply for approval to reverse. It might be possible to have this issue, as well as any other tolling issues arising from the use of the extension, considered at the upcoming IPL toll hearing, which will likely be held sometime in the last quarter of 1991. If the possibility of reversal is not seriously contemplated for the near future, it might, however, be more appropriate to postpone the consideration of the tolling issue until a later date.

Neither the NEB Act nor the regulations require that an oral public hearing be convened to consider applications for deactivation, reactivation, a section 58 order, or a determination of a tolling issue. Nonetheless, the Board would likely solicit comments from interested parties on any of the above. An application for an order to allow reversal of the line, or one to have tolling issues decided, would most probably be considered at an oral public hearing.

Appendix I

Minister of Energy, Mines and Resources

CANADA

Ministre de l'Énergie, des Mines et des Ressources

JAN - 8 1991

Mr. R. Priddle
Chairman
National Energy Board
473 Albert Street
Ottawa, Ontario
K1A 0E5

Dear Mr. Priddle/Roland.

The continued operation of the Sarnia-Montreal section of the Interprovincial pipeline has been a subject of discussion in the oil industry for some months. Diminishing supply of light Western Canadian crude oil, more economic foreign crude supply opportunities for Montreal refiners and long transit times to move oil from Sarnia to Montreal have all contributed to uncertainty about the use of this pipeline.

Decisions on the future of the Sarnia-Montreal pipeline have potential energy policy implications for the Government of Canada. Accordingly I am asking the Board, under Section 26, Part II of the National Energy Board Act, to review and report on the prospects for and implications of closure of the Sarnia-Montreal pipeline and the options available to industry and/or government for maintaining the line in an operating mode with west-east or east-west flow.

In carrying out its study, the Board should seek the views of interested parties to the extent that this would contribute to the Board's better understanding of relevant crude supply matters. Without restricting the scope of the study, the Board should have particular regard to the following:

1. Canadian crude oil supply and demand projections.

2. Supply options for Eastern Canadian refiners, including security of supply implications.

3. Impact of closure on markets and prices of Canadian crude oil, including heavy crude exports.

4. Supply and economic aspects of a potential reversal or bi-directional operation of the pipeline.

5. Options open to industry and the government to maintain prolonged west-to-east use of the line and their implications, costs and benefits.

6. Environmental implications that may result from changes to the current operation of the line.

I would hope that the Board could complete its analysis by the end of the first quarter.

Yours sincerely,

Jake Epp

Appendix II

The Portland-Montreal Pipeline System - History and Description

The Montreal Pipeline Company Ltd. and its wholly owned subsidiary, Portland Pipe Line Corporation, own and operate the crude oil pipeline system extending from Portland, Maine, to Montreal.

The Montreal Pipe Line Company Ltd. was incorporated in Canada in 1941 under the Companies Act, while the Portland Pipe Line Corporation was incorporated in the same year in the United States. The Canadian operation is under the jurisdiction of the National Energy Board while the American company falls under the authority of the Federal Energy Regulatory Commission.

Because of the existence of the system, tankers do not have to travel the extra 3000 kilometers to Montreal, larger tankers can be used because of the port facilities at Portland, and shipping is available 12 months of the year.

Besides a tanker unloading terminal and tank farm at South Portland, Maine, there were originally three main transmission lines traversing a distance of 267 km in the U.S. and 113 km in Canada. A 12-inch diameter line was laid in 1941, an 18-inch in 1950, and a 24-inch diameter line in 1965.

As a result of lower throughputs following the opening of IPL's Sarnia-Montreal extension in 1976, the active capacity of the Portland-Montreal system was reduced from 87 000 cubic metres per day to 40 000 cubic metres per day in 1980. This was accomplished by the removal of the 12-inch line from service and removal of pumping equipment from the other two lines. In 1981, the 12-inch line was abandoned, along with the related above-ground facilities. In 1986, the National Energy Board approved the deactivation of the 18-inch line and, later in the year, gave Shell Canada Limited permission to convert a portion of the 18-inch line to natural gas use.

Ownership

Ownership of the Portland-Montreal pipeline system is as follows:

Imperial Oil Limited	57%
Shell Canada Limited	19%
Petro-Canada Products Inc.	24%

Appendix III

The Interprovincial Pipe Line System - History and Description

The Interprovincial/Lakehead pipeline system is one of the largest oil pipelines in the world. The system consists of a total of 11 completed lines, plus loops stretching some 3 700 km from Edmonton, Alberta to Montreal, Quebec.

The IPL system was originally developed in 1947, as a wholly owned subsidiary of Imperial Oil Ltd., to transport crude oil from the Leduc field in Alberta to Regina. Before plans were completed, additional crude oil was discovered near Redwater, Alberta, and it was then decided to extend the pipeline to Superior, Wisconsin. At the same time, other oil companies were invited to participate in the ownership of the expanded pipeline, and Imperial's interest was reduced to 33%. The other original shareholders were Gulf (7%) and Shell (2%), with the remaining 58% spread over some 22,000 shareholders, each with less than 2% of the shares. In 1983, Hiram Walker Resources Ltd., which became a subsidiary of Gulf Canada Corporation in 1986, acquired a 34% interest. In 1990, Imperial sold its interest in IPL.

Interprovincial Pipe Line Company was incorporated by a special act of Parliament on April 30, 1949. Lakehead Pipe Line Company Inc., a wholly owned subsidiary incorporated in the United States on August 29 of the same year, operates the American portions of the system.

The IPL/Lakehead system currently consists of (a) three parallel lines from Edmonton to Superior, Wisconsin; (b) two lines from Superior to Sarnia, Ontario, one via the Straits of Mackinac (light crudes and the natural gas liquids mix) and one via Chicago; (c) two lines from Sarnia to the Toronto area with lateral extensions to Buffalo, New York and Nanticoke, Ontario; and (d) a crude oil line from Sarnia to Montreal which has a lateral extension to the Petro-Canada refinery at Clarkson, Ontario.

The IPL/Lakehead system is under the jurisdiction of the National Energy Board in Canada and the Federal Energy Regulatory Commission in the United States.

Montreal Extension

The extension from Sarnia to Montreal, which provides for the delivery of western Canadian crude to Quebec, was completed in 1976. Construction was premised on security-of-supply considerations rather than strictly economic reasons. IPL and the federal government entered into a deficiency agreement whereby the government would pay the deficiency if operating revenue were insufficient to meet the fixed and variable costs of the line. The term of the Deficiency Agreement is 20 years, ending in 1996.

The Sarnia-Montreal section is 832 km in length and 762 mm in diameter, with five pump stations and a total installed power of 16 800 kw. Current capacity of the line is 54 000 cubic metres per day.

The minimum continuous flow which can be maintained through the Montreal extension, assuming the line is carrying light crude oil, is dependent on the line temperature and varies from about 7 000 cubic metres per day in summer to 16 000 cubic metres per day in winter.

In order to function at reasonable efficiency and to avoid operational problems, a pipeline must maintain sufficient flowing velocity to maintain turbulent flow. Lower flow rates can be achieved by stop-and-go pumping. Such operation on a regular basis places additional stresses on the pipe and pipeline equipment. Over a long period of time, intermittent operation would likely contribute to a shorter useful life for the pipe and related equipment.

Appendix IV

Deficiency Agreement and IPL Toll Design

IPL's application to construct the Montreal extension was in response to the federal government's policy that, in the interest of security of oil supply, there be an extension to IPL's pipeline, from Sarnia to Montreal. Between the time of IPL's construction application to the Board in March 1974, and the Board's issuance of a certificate for construction of the facilities in May 1975, IPL became increasingly concerned with the question of whether or not there would be sufficient crude oil supply in western Canada to accommodate both the traditional Canadian markets and the markets to be served by the extension. As a result, IPL decided that it could not proceed with the project without revenue assurances. IPL and the federal government then negotiated the Deficiency Agreement of 8 April 1975. This Agreement guarantees IPL its recovery of the fixed and variable costs incurred in operating the Sarnia-Montreal extension each year over the twenty-year term of the Agreement. It is structured to accommodate a possible reversal of the flow of oil on the Sarnia-Montreal extension, and provides the federal government the option to purchase the line from IPL.

In any year, if the revenues earned in respect of the extension, from tolls approved by the Board, fall short of the total fixed and variable costs as defined in the Deficiency Agreement, the federal government will pay the amount of the deficiency to IPL. Each year, within 120 days of making a deficiency payment, the federal government may exercise its option to purchase the extension from IPL, at its capital cost less accumulated depreciation based on a twenty-year life, plus legal costs and other disbursements incurred by IPL in the sale.

As part of its first hearing for IPL's tolls and tariffs, the Board outlined a methodology for the calculation of tolls in respect of the Sarnia-Montreal extension. Essentially, the Board set out two methods of calculation - an "integrated" method and a "two-part method" - and developed a test to determine which method would be appropriate for a given year. The integrated method of toll design would combine the revenue requirement of the Sarnia-Montreal extension with that of the Older System to derive tolls based on the total throughput of the system. Under the two-part method, tolls for the Older System would be calculated separately from those of the extension and would be set equal to the tolls that would result, hypothetically, if the extension did not exist. Tolls for the Sarnia-Montreal extension would be derived from its revenue requirement and throughput, adjusted for an upstream credit. This credit would represent the additional income projected to be earned on the Older System as a result of throughput destined for Montreal. The method of toll design to apply in any given test year would be that which would result in lower tolls for shippers on the Older System.

In the first toll hearing for IPL, the Board also considered the costs to be included in the Sarnia-Montreal extension's revenue requirement for toll purposes. The Board found that approximately $11 million had been imprudently incurred on the construction of the line, and disallowed this amount from the rate base. The Board did not find the depreciation rate of five percent, proposed by IPL and based on the depreciation calculation in the Deficiency Agreement, to be reasonable, and directed that depreciation rates comparable to those in effect on the Older System (which averaged approximately three percent) be applied to the extension in determining the amount of depreciation expense to be included in the revenue requirement. For purposes of calculating accumulated depreciation, however, the Board accepted the rate of five percent. Since the Deficiency Agreement provides for a five percent depreciation rate, this arrangement results in approximately three percent depreciation being charged to shippers through tolls approved by the Board, and the remaining two percent being absorbed by the federal government through the Deficiency Agreement.

In this light, the federal government's deficiency payments to IPL can be viewed as comprising several components. These include primarily: a difference in depreciation expense resulting from the rates approved by the Board; a difference between the return allowed by the Board on the extension, and IPL's actual interest expense under the Deficiency Agreement; depreciation and interest expense on the capital cost which the Board disallowed from IPL's rate base as being imprudent; and, the amount by which the Sarnia-Montreal extension's revenue may differ from its revenue requirement for toll purposes.

Until 1984, the tolls for the extension were calculated using the two-part method of toll design. While the toll design test showed that tolls for 1980 could have been calculated on an integrated basis, the Board believed that this phenomenon would be shortlived and directed that the tolls be calculated using the two-part method. For 1984, the toll methodology test again indicated that the integrated method of toll design should be used, and the Board adopted this approach. In the toll hearing held for IPL's 1987 test year, the Board found that the toll methodology test was unfair, and that it should be discontinued. Although the Board approved the use of integrated tolls for 1987, it indicated that the ultimate toll methodology for the extension, given an elimination of the test, had not been sufficiently addressed during that hearing and that this issue would be examined at the earliest opportunity. To date, this issue has not been examined and IPL's tolls have continued to be calculated on an integrated basis. The Board expects to hold a toll hearing for IPL during 1991.

The Montreal extension's transportation revenue requirement approved by the Board for 1991 was $21 million. Given the integrated method of toll design, approximately $4 million was projected to be generated from throughput movements on the extension itself. The remaining $17 million was expected to be recovered from the integrated revenue generated on the Older System, on the extension's behalf (through a credit included in each of the tolls). Approximately $9 million in additional fixed and variable costs on the Montreal extension for 1991, comprising those items which have been disallowed by the Board for toll purposes, are recoverable by IPL through the Deficiency Payment.

Appendix V

Domestic Supply

This Appendix describes the basis for the crude oil supply projections described in the report and summarizes views expressed by interested parties during the consultation process.

In discussing the domestic supply outlook for the next ten years, focus is placed on a control case and the range of uncertainty around it, based mainly on uncertainties surrounding the crude oil price projection. The projection is then compared to the supply range provided by interested parties, and views of parties who made no explicit supply submissions are summarized. Finally, the analysis is discussed in detail by focussing on light and heavy crude oil supply.

The current Board staff control case supply projection, which is depicted in Figure V-1, is based on staff analysis completed following recent consultations with interested parties regarding the update of the "Canadian Energy Supply and Demand" report. It shows a gradual decline in total productive capacity from an average of 267 000 cubic metres per day in 1990 to a low of 242 000 cubic metres per day in 1996. After 1996, supply is expected to gradually increase as significant production from the East Coast offshore commences, given the current development plans for Hibernia, and as further bitumen development becomes viable as crude oil prices increase. The projection is based on a crude oil price which, in 1990 dollars, increases from about $U.S. 20 per barrel in 1991 to about $U.S. 23 per barrel in the year 2000. This price track falls within what is considered to be a range of sustainable prices that is based on past price behavior, available studies, and consultations with knowledgeable analysts and participants in the energy market. The upper and lower bounds of this range were established by assessing the likelihood of prices being sustained at even higher or lower levels over the period. At any time, oil prices could exceed the bounds of this range for a number of reasons. Once that happens, however, it is expected that market reactions would have the effect of moving the price back into the range. The upper bound of our range, expressed in 1990 US dollars, increases from $22 in 1991 to just over $27 in 2000. The lower bound increases from $18 in 1991 to about $20 in 2000. The range of uncertainty shown around the NEB supply projection reflects the impact on supply of the upper and lower bounds of the price range.

A somewhat different perspective on the possible range of domestic crude oil supply is provided by the detailed supply projections submitted by IPL, Shell, Esso and the CPA. These projections are based on different views about future crude oil prices, which were not explicitly stated in the submissions. The CPA submission reflects the combined views of its membership. The Shell submission included both a low and a high crude oil price scenario. Shell's low case provided the bottom of the range of submittors' projections, whereas Shell's high case, the IPL projection and the CPA projection were very similar and provided the top end of the range of views of submittors. All of the projections in the high range included supply from the proposed OSLO project beginning in 1997. The IPL projection was rather high in the earlier years because its allowance for conventional crude oil supply from Alberta, which was based on a 1988 AERCB projection, was higher than projections provided by other submittors.

IPAC, along with several producers, expressed general views on the availability of supply to the Sarnia-Montreal pipeline. These submissions suggest that there will be sufficient domestic supply for the Quebec market, and by implication, that domestic crude oil supply could be somewhat higher than the supply projections discussed above. IPAC did emphasize the point that advances in horizontal drilling techniques could contribute significantly to future supply, given the remaining crude oil potential in western Canada. However, the differences may also be explained by a different view of future export levels to the United States.

It would appear that total domestic crude oil supply will, at best, stabilize at current levels over the first five to six years of the projection period, but is more likely to decline somewhat. The specific profile is sensitive to both crude oil price projections and the impact of technological change. While higher prices and improvements in technology could have the effect of improving Canada's crude oil supply capability somewhat relative to these projections, there is also a downside which could arise if crude prices were below the lower bound of the price range used in our projection.

For the purpose of assessing the possible utilization of the Sarnia-Montreal pipeline it is necessary to focus on certain components of the Board's overall supply projection; in particular, western Canadian light crude oil and equivalent and to a lesser degree heavy crude oil.

Light Crude Oil and Equivalent Supply

Light crude oil and equivalent supply encompasses conventional light crude oil, synthetic crude oil and pentanes plus. Conventional light crude oil is further subdivided into a light sweet blend and a light sour blend. Light sweet blend currently makes up nearly 80 percent of conventional light crude oil supply and our analysis indicates that this percentage is likely to remain relatively constant over the projection period. Table V-1 shows the projected supply of light crude oil and equivalent to the year 2000 by supply component. Pentanes plus are included in the light crude oil supply but a significant portion of this supply is added as a diluent to bitumen as well as to some conventional heavy crude oils in order to decrease the viscosity of these supply components. Without blending with diluent, these supply components would not meet the viscosity specifications set by the pipeline companies. This adjustment is reflected in the supply projections for light crude oil provided in Table V-1.

The table illustrates the anticipated gradual change in the composition of Canada's light crude oil supply. The contribution of conventional light crude oil supply from the Western Canadian Sedimentary Basin is expected to decline considerably as annual reserves additions are expected to fall short of annual production. The contribution of synthetic crude oil from mining plants is expected to increase gradually as debottlenecking of the existing plants continues. Synthetic crude oil supply from upgraders is expected to increase significantly in 1993 when the Bi-Provincial Upgrader is scheduled to start up. The contribution from pentanes plus remains relatively constant, as increases in supply related to expected growth in natural gas production are largely offset by increases in diluent demand associated with the anticipated growth in bitumen production. Supply from the East Coast offshore starts modestly in 1992 when production from the Cohasset/Panuke fields is expected to come onstream. These fields are expected to be nearly depleted by 1996, when production from the Hibernia field is expected to start contributing to supply.

Of the supply components discussed above, all but offshore crude oil are directly relevant to the future utilization of the Sarnia-Montreal pipeline. All of these supply components have some uncertainty associated with them. For light crude oil, both estimates of established reserves and projected reserves additions affect future supply. Established reserves estimates are, for the most part, based on observed production declines, but higher prices could lead to temporarily higher rates of production. Crude oil prices and technological advances could have some effect on reserves additions, but the impact of such effects is gradual and would probably not be too significant until near the end of the projection period. In the case of synthetic crude oil, major decisions on future projects are taken on the basis of a perception of future crude oil prices, and although such decisions have a major impact on supply over the longer term, there is virtually no impact on short term supply because of the long lead times associated with project development. However, supply from the proposed OSLO project could be forthcoming toward the latter part of the projection period if this project proceeds. Our projection of pentanes plus reflects production from the recently discovered Caroline gas field and the supply associated with expected increases in gas exports. Diluent demand is affected by changes in bitumen supply.

The light crude oil supply from western Canada according to the control case is expected to decline from about 190 000 cubic metres per day in 1990 to 141 000 cubic metres per day in the year 2000. The total light crude oil supply, including offshore production, is anticipated in the control case to be 172 000 cubic metres per day in the year 2000.

From a review of the submissions that provided a detailed supply projection, it is concluded, after making appropriate adjustments for diluent requirements and excluding offshore supply, that in respect to light crude oil supply there was reasonable agreement between our control case projection and the projections submitted by others. In the first half of the projection period, the differences were rather modest, with our analysis being slightly higher than most others. During the second half, our projection fell more in the middle of the range, with the differences between our projection and those of submittors being at most 15 percent. The differences are generally difficult to attribute entirely to one specific assumption. However, it would appear that the higher projections included supply from the OSLO project starting in 1997, and lower ones were generally based on significantly lower crude oil prices than used in our control case outlook.

Heavy Crude Oil Supply

Heavy crude oil supply encompasses conventional heavy crude oil, bitumen and pentanes plus used as diluent. A portion of the blended heavy crude oil is used as upgrader feedstock. The supply projections for the different supply components are summarized in Table V-1, with appropriate adjustments for diluent and heavy crude used as upgrader feedstock.

Our projection of conventional heavy crude oil supply includes crude oil classified by some others as medium, as well as crude oil generally classified as heavy. All heavy and medium crude oils are sour (i.e., they have high sulphur content). Table V-1 shows that conventional heavy crude oil supply is expected to increase moderately over the first half of the projection period, before a moderate decline commences. This increase in supply is anticipated to arise from continued exploratory successes and advances in horizontal drilling technology.

Bitumen supply is expected to gradually increase, given projected crude oil prices and our assessment of the costs of these projects. This projection is rather sensitive to future crude oil prices, as many projects become profitable once prices exceed a particular level.

As mentioned above, the supply of heavy crude oil includes pentanes plus used as diluent and is reduced by the quantity of heavy crude used as upgrader feedstock. Increases in diluent requirements are primarily related to the growth in bitumen supply. Upgrader feedstock requirements are associated initially with the CO-OP upgrader in Regina. Commencing in 1993, feedstock requirements for the Bi-Provincial Upgrader are also included.

Heavy crude oil supply is expected to increase gradually over the projection period, from 76 000 cubic metres per day in 1990 to 87 000 cubic metres per day in the year 2000. This supply projection falls between the upper and lower bounds of other projections which were submitted.

Figure V-1

Canadian Crude Oil Supply Range of Projections

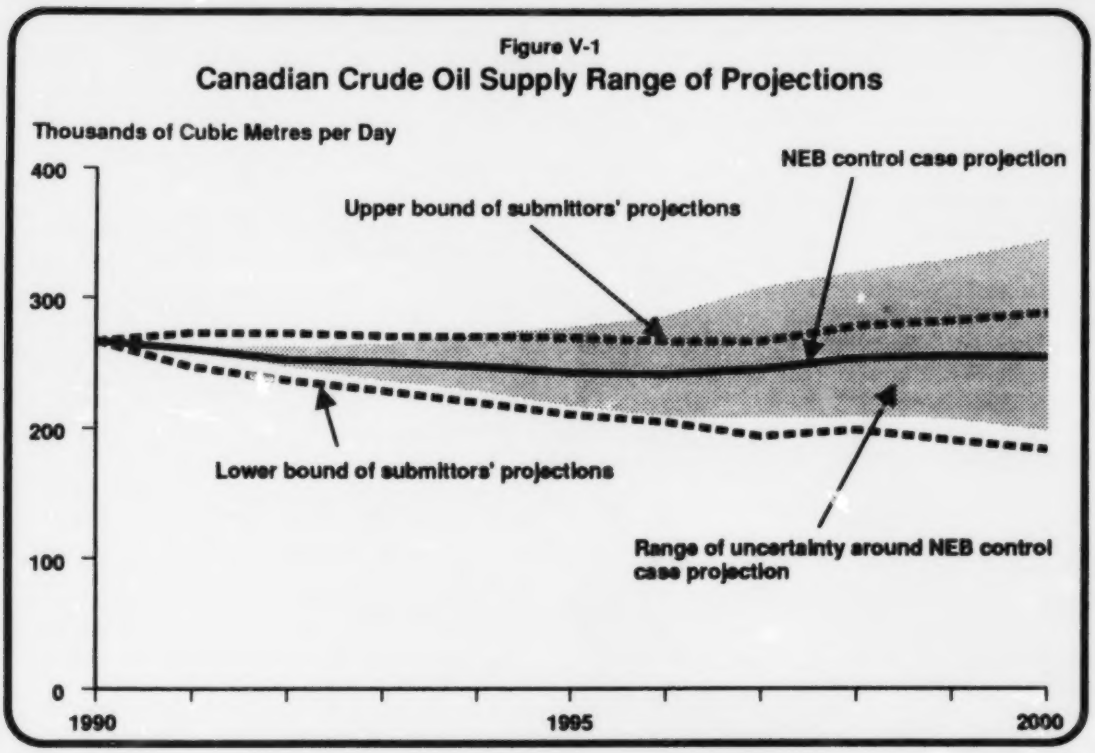


Table V-1

Productive Capacity of Crude Oil and Equivalent - Total Canada

Control Case

(Thousands of Cubic Metres per Day)

	Light									Heavy						
	WCSB Light	Mining Synthetic	Upgraded Synthetic	Pentanes Plus	Gross Diluent Req. [b]	Recycled Diluent [c]	WCSB Light & Equivalent Sub Total	E. Coast Light [a]	Light and Equivalent Total	Conventional Heavy	Bitumen	Gross Diluent Req.	Blended Heavy Total	Upgrader Feedstock [d]	Net Available Heavy	Total Crude & Equivalent
1990	144.7	32.2	8.0	18.6	-14.1	1.0	190.4	0.1	190.5	49.7	20.6	14.1	84.4	-8.0	76.4	266.9
1991	137.4	33.4	8.0	19.6	-14.1	1.0	185.3	0.1	185.4	48.8	20.9	14.1	83.8	-8.0	75.8	261.2
1992	126.2	33.9	8.0	20.6	-15.0	1.0	174.7	2.7	177.4	48.1	23.0	15.0	86.1	-8.0	78.1	255.5
1993	117.2	34.8	10.7	23.8	-15.6	1.8	172.7	2.7	175.4	47.9	24.6	15.6	88.1	-11.5	76.6	252.0
1994	110.1	36.6	14.4	24.1	-16.0	2.9	172.1	2.7	174.8	48.3	25.4	16.0	89.7	-16.3	73.4	248.2
1995	104.4	36.4	14.4	24.1	-16.5	2.9	165.7	2.7	168.4	49.1	26.5	16.5	92.1	-16.3	75.8	244.2
1996	99.4	36.4	14.4	24.2	-16.9	2.9	160.4	4.4	164.8	49.5	27.2	16.9	93.6	-16.3	77.3	242.1
1997	94.7	37.6	14.4	24.3	-17.0	2.9	156.9	11.9	168.8	49.5	27.5	17.0	94.0	-16.3	77.7	246.5
1998	90.4	37.6	14.4	24.1	-17.3	2.9	152.1	24.5	176.6	48.7	28.4	17.3	94.4	-16.3	78.1	254.7
1999	86.4	37.6	14.4	23.8	-18.6	2.9	146.5	31.5	178.0	47.5	31.9	18.6	98.0	-16.3	81.7	259.7
2000	82.6	37.6	14.4	23.8	-20.4	2.9	140.9	31.5	172.4	46.2	36.5	20.4	103.1	-16.3	86.8	259.2

Notes [a] Includes production of 100 cubic metres per day from Bent Horn.

[b] Diluent required for heavy crude and bitumen blending is removed from the light crude oil supply and added to the heavy crude oil supply. Diluent requirements in excess of the supply of pentanes plus are assumed to be met by light crude.

[c] Includes diluent currently being recycled (approximately 1 thousand cubic metres per day) and future volumes to be recycled from upgraders.

[d] Blended heavy crude used as upgrader feedstock is included in the light crude supply as upgraded synthetic crude and recycled diluent.

Appendix VI

Petroleum Product Demand

(Thousands of Cubic Metres per Day)

	1990	1991	1992	1993	1994	1995	2000
Atlantic	33.5	33.7	33.8	34.2	34.4	34.5	35.6
Quebec	52.1	51.9	51.8	51.9	52.1	52.4	52.9
Ontario	78.6	79.4	79.9	80.8	81.6	82.2	85.1
Prairies & NWT	48.0	47.8	47.5	47.9	48.0	48.3	49.2
B.C. & Yukon	28.0	27.5	27.8	28.1	28.4	28.6	29.7
Total Canada	**240.2**	**240.3**	**240.8**	**242.9**	**244.5**	**246.0**	**252.5**

Appendix VII-1

Refinery Feedstock Requirements and Sources

Atlantic

	1990	1991	1992	1993	1994	1995	2000
Feedstock Requirements (Thousands of Cubic Metres)							
Domestic Product Demand [a]	12215	12316	12407	12487	12561	12604	13037
Deduct Product Imports	-2624	-3000	-3000	-3000	-3000	-3000	-3000
Add Product Exports	6467	7000	7000	7000	7000	7000	7000
Net Regional Transfers -In/+Out	510	500	500	500	500	500	500
Product Inventory +Build/-Draw	-213	0	0	0	0	0	0
Add Own Consumption	970	998	1003	1008	1012	1015	1040
Total	**17326**	**17813**	**17910**	**17995**	**18073**	**18119**	**18577**
Per Day	**47.5**	**48.8**	**48.9**	**49.3**	**49.5**	**49.6**	**50.8**
Feedstock Sources (Thousands of Cubic Metres Per Day)							
Domestic: Heavy	0.4	0.0	0.0	0.0	0.0	0.0	0.0
Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Imports	47.2	48.8	48.9	49.3	49.5	49.6	50.8
Inventory Change	-0.1	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	47.5	48.8	48.9	49.3	49.5	49.6	50.8
Partially Processed Oil and Other Material	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas Plant Butanes/MTBE	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**47.5**	**48.8**	**48.9**	**49.3**	**49.5**	**49.6**	**50.8**

Note: [a] Domestic product demand includes end-use consumption, refinery LPG sales and oil used to generate electricity and steam.

Appendix VII-2

Refinery Feedstock Requirements and Sources

Quebec

	1990	1991	1992	1993	1994	1995	2000
Feedstock Requirements (Thousands of Cubic Metres)							
Domestic Product Demand [a]	18999	18943	18942	18958	19038	19111	19350
Deduct Product Imports	-2945	-5000	-5000	-5000	-5000	-5000	-5000
Add Product Exports	575	750	750	750	750	750	750
Net Regional Transfers -In/+Out	204	-500	-500	-500	-500	-500	-500
Product Inventory +Build/-Draw	-1754	0	0	0	0	0	0
Add Own Consumption	962	954	954	955	961	966	982
Total	16041	15147	15146	15163	15249	15327	15581
Per Day	43.9	41.5	41.4	41.5	41.8	42.0	42.6
Feedstock Sources (Thousands of Cubic Metres Per Day)							
Domestic: Heavy	4.0	1.4	0.0	0.0	0.0	0.0	0.0
Light	7.9	5.0	0.0	0.0	0.0	0.0	0.0
Imports	32.2	35.1	41.4	41.5	41.8	42.0	42.6
Inventory Change	-0.9	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	43.2	41.5	41.4	41.5	41.8	42.0	42.6
Partially Processed Oil and Other Material	0.7	0.0	0.0	0.0	0.0	0.0	0.0
Gas Plant Butanes/MTBE	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	43.9	41.5	41.4	41.5	41.8	42.0	42.6

Note: [a] Domestic product demand includes end-use consumption, refinery LPG sales and oil used to generate electricity and steam.

Appendix VII-3

Refinery Feedstock Requirements and Sources

Ontario

	1990	1991	1992	1993	1994	1995	2000
Feedstock Requirements (Thousands of Cubic Metres)							
Domestic Product Demand [a]	28685	28984	29237	29494	29769	30019	31176
Deduct Product Imports	-1335	-1300	-1300	-1300	-1300	-1300	-1300
Add Product Exports	2827	3000	3000	3000	3000	3000	3000
Net Regional Transfers -In/+Out	-1596	-1500	-1500	-1500	-1500	-1500	-1500
Product Inventory +Build/-Draw	-317	0	0	0	0	0	0
Add Own Consumption	1965	2029	2046	2064	2083	2101	2181
Total	**30229**	**31213**	**31484**	**31758**	**32052**	**32320**	**33557**
Per Day	**82.8**	**85.5**	**86.0**	**87.0**	**87.8**	**88.5**	**91.7**
Feedstock Sources (Thousands of Cubic Metres Per Day)							
Domestic: Heavy	8.4	10.4	10.5	10.7	10.7	11.6	12.9
Light	68.5	71.4	71.8	72.6	73.4	71.7	45.8
Imports	2.5	0.0	0.0	0.0	0.0	1.5	29.3
Inventory Change	0.2	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	79.6	81.8	82.3	83.3	84.1	84.8	88.0
Partially Processed Oil and Other Material	2.9	3.4	3.4	3.4	3.4	3.4	3.4
Gas Plant Butanes/MTBE	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	**82.8**	**85.5**	**86.0**	**87.0**	**87.8**	**88.5**	**91.7**

Note: [a] Domestic product demand includes end-use consumption, refinery LPG sales and oil used to generate electricity and steam.

Appendix VII-4

Refinery Feedstock Requirements and Sources

Prairies & NWT

	1990	1991	1992	1993	1994	1995	2000
Feedstock Requirements (Thousands of Cubic Metres)							
Domestic Product Demand [a]	17527	17429	17383	17460	17527	17612	17991
Deduct Product Imports	-12	0	0	0	0	0	0
Add Product Exports	847	1000	1000	1000	1000	1000	1000
Net Regional Transfers -In/+Out	3425	4500	4500	4500	4500	4500	4500
Product Inventory +Build/-Draw	160	0	0	0	0	0	0
Add Own Consumption	1155	1207	1204	1208	1212	1216	1236
Total	**23102**	**24136**	**24087**	**24168**	**24239**	**24329**	**24727**
Per Day	**63.3**	**66.1**	**65.8**	**66.2**	**66.4**	**66.7**	**67.6**
Feedstock Sources (Thousands of Cubic Metres Per Day)							
Domestic: Heavy	4.9	4.8	4.9	5.1	5.1	5.4	6.1
Light	56.0	58.3	57.9	58.1	58.3	58.3	58.5
Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Inventory Change	-0.2	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	60.7	63.1	62.8	63.2	63.4	63.7	64.6
Partially Processed Oil and Other Material	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Gas Plant Butanes/MTBE	2.0	2.4	2.4	2.4	2.4	2.4	2.4
Total	**63.3**	**66.1**	**65.8**	**66.2**	**66.4**	**66.7**	**67.6**

Note: [a] Domestic product demand includes end-use consumption, refinery LPG sales and oil used to generate electricity and steam.

Appendix VII-5

Refinery Feedstock Requirements and Sources

British Columbia & Yukon

	1990	1991	1992	1993	1994	1995	2000
Feedstock Requirements (Thousands of Cubic Metres)							
Domestic Product Demand [a]	10248	10051	10160	10262	10365	10454	10856
Deduct Product Imports	-510	-600	-600	-600	-600	-600	-600
Add Product Exports	887	800	800	800	800	800	800
Net Regional Transfers -In/+Out	-2543	-3000	-3000	-3000	-3000	-3000	-3000
Product Inventory +Build/-Draw	122	0	0	0	0	0	0
Add Own Consumption	478	422	428	434	440	445	469
Total	**8682**	**7673**	**7789**	**7897**	**8006**	**8100**	**8525**
Per Day	**23.8**	**21.0**	**21.3**	**21.6**	**21.9**	**22.2**	**23.3**
Feedstock Sources (Thousands of Cubic Metres Per Day)							
Domestic: Heavy	0.3	0.6	0.6	0.6	0.6	0.7	0.8
Light	17.8	14.6	14.9	15.2	15.5	15.7	16.7
Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Inventory Change	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	18.1	15.2	15.5	15.8	16.1	16.4	17.5
Partially Processed Oil and Other Material	5.6	5.7	5.7	5.7	5.7	5.7	5.7
Gas Plant Butanes/MTBE	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**23.8**	**21.0**	**21.3**	**21.6**	**21.9**	**22.2**	**23.3**

Note: [a] Domestic product demand includes end-use consumption, refinery LPG sales and oil used to generate electricity and steam.

Appendix VII-6

Refinery Feedstock Requirements and Sources

Total Canada

	1990	1991	1992	1993	1994	1995	2000
Feedstock Requirements (Thousands of Cubic Metres)							
Domestic Product Demand [a]	87674	87723	88129	88661	89260	89801	92409
Deduct Product Imports	-7426	-9900	-9900	-9900	-9900	-9900	-9900
Add Product Exports	11603	12550	12550	12550	12550	12550	12550
Net Regional Transfers -In/+Out	0	0	0	0	0	0	0
Product Inventory +Build/-Draw	-2001	0	0	0	0	0	0
Add Own Consumption	5530	5609	5636	5670	5708	5743	5908
Total	**95380**	**95982**	**96416**	**96981**	**97619**	**98194**	**100968**
Per Day	**261.3**	**263.0**	**263.4**	**265.7**	**267.4**	**269.0**	**275.9**
Feedstock Sources (Thousands of Cubic Metres Per Day)							
Domestic: Heavy	18.0	17.2	16.0	16.4	16.4	17.7	19.8
Light	150.2	149.4	144.6	146.0	147.3	145.7	120.9
Imports	81.9	83.9	90.3	90.8	91.3	93.1	122.6
Inventory Change	-1.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	249.1	250.5	250.9	253.2	254.9	256.5	263.4
Partially Processed Oil and Other Material	9.8	9.7	9.7	9.7	9.7	9.7	9.7
Gas Plant Butanes/MTBE	2.4	2.8	2.8	2.8	2.8	2.8	2.8
Total	**261.3**	**263.0**	**263.4**	**265.7**	**267.4**	**269.0**	**275.9**

Note: [a] Domestic product demand includes end-use consumption, refinery LPG sales and oil used to generate electricity and steam.

Appendix VIII

Supply and Disposition of Domestic Heavy Crude Oil

(Thousands of Cubic Metres per Day)

	1990	1991	1992	1993	1994	1995	2000
Total Supply	**76.9(A)**	**75.8**	**78.1**	**76.6**	**73.4**	**75.8**	**86.8**
Disposition							
Atlantic	0.4	-	-	-	-	-	-
Quebec	4.0	1.4	-	-	-	-	-
Ontario	8.4	10.4	10.5	10.7	10.7	11.6	12.9
Prairies & NWT	4.9	4.8	4.9	5.1	5.1	5.4	6.1
B.C. & Yukon	0.3	0.6	0.6	0.6	0.6	0.7	0.8
Total Canada	**18.0**	**17.2**	**16.0**	**16.4**	**16.4**	**17.7**	**19.8**
Exports	58.9	58.6	62.1	60.2	57.0	58.1	67.0
Total Disposition	**76.9**	**75.8**	**78.1**	**76.6**	**73.4**	**75.8**	**86.8**

NOTE

(A) Includes inventory draw of 0.5 thousand cubic metres per day.

Appendix IX

Supply and Disposition of Domestic Light Crude Oil and Equivalent

(Thousands of Cubic Metres per Day)

	1990	1991	1992	1993	1994	1995	2000
Supply							
Conventional Light Sweet (A)	119.1	114.4	105.7	102.0	97.4	92.5	71.1
Conventional Light Sour	31.1	29.5	27.1	25.2	23.7	22.4	17.8
Synthetic	40.2	41.4	41.9	45.5	51.0	50.8	52.0
East Coast(B)	0.1	0.1	2.7	2.7	2.7	2.7	31.5
Inventory Draw	4.2	-	-	-	-	-	-
Total Supply	**194.7**	**185.4**	**177.4**	**175.4**	**174.8**	**168.4**	**172.4**
Disposition							
Atlantic	-	-	-	-	-	-	-
Quebec	7.9	5.0	-	-	-	-	-
Ontario	68.5	71.5	71.8	72.6	73.5	71.7	45.8
Prairies & NWT	56.0	58.3	57.9	58.2	58.3	58.3	58.4
B.C. & Yukon	17.8	14.6	14.9	15.2	15.5	15.7	16.7
Total Canada	**150.2**	**149.4**	**144.6**	**146.0**	**147.3**	**145.7**	**120.9**
Exports	44.5	36.0	32.8	29.4	27.5	22.7	51.5
Total Disposition	**194.7**	**185.4**	**177.4**	**175.4**	**174.8**	**168.4**	**172.4**

NOTE

(A) Includes condensate

(B) Includes 0.1 $10^3 m^3/d$ from Bent Horn in the arctic islands

Appendix X

Light Crude Oil Requirements and Domestic Supply for Ontario

(Thousands of Cubic Metres per Day)

	1990	1991	1992	1993	1994	1995	2000
Total Ontario Feedstock Requirements	**82.8**	**85.5**	**86.0**	**87.0**	**87.8**	**88.5**	**91.7**
Less: Domestic Supply other than Light Crude							
Heavy Crude	(8.4)	(10.4)	(10.5)	(10.7)	(10.7)	(11.6)	(12.9)
Partially Processed Oil	(2.9)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)
Gas Plant Butanes	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
Ontario Requirements for Light Crude	**71.2**	**71.4**	**71.8**	**72.6**	**73.4**	**73.2**	**75.1**
Total Available Domestic							
Light Crude Supply (A)	194.6	185.3	174.7	172.7	172.1	165.7	140.9
Less: Supply for Quebec	(7.9)	(5.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Supply for Prairies	(56.0)	(58.3)	(57.9)	(58.1)	(58.3)	(58.3)	(58.5)
Supply for B.C.	(17.8)	(14.6)	(14.9)	(15.2)	(15.5)	(15.7)	(16.7)
Provision for Exports	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)
Domestic Light Crude Supply Available for Ontario	**92.9**	**87.4**	**81.9**	**79.4**	**78.3**	**71.7**	**45.7**
Surplus (+) or Shortfall (-)	**21.7**	**16.0**	**10.1**	**6.8**	**4.9**	**(1.5)**	**(29.4)**

Note

(A) Excludes East Coast production

Appendix XI

Representative Light Sweet Crude Oil Supply Costs at Montreal

($U.S. per barrel)

For the purpose of this analysis, it has been assumed that, for longer term planning purposes, WTI and Brent will be at parity in Cushing. Thus, the illustrative parity price has been set at $U.S. 20.00 per barrel, based on transportation from the U.S. Gulf to Cushing on the Arco/Texaco pipeline systems. This implies an F.O.B. Brent price of about $U.S. 17.80 per barrel.

	Canadian	WTI	Brent via		
			U.S. Gulf-Capline	U.S. Gulf-Arco/Texaco Pipeline	Portland/Montreal Pipeline
F.O.B.	19.40		17.80	17.80	17.80
Ocean Freight			1.40	1.40	1.20
Ocean Loss			0.10	0.10	0.05
Landed Cost			**19.30**	**19.30**	**19.05**
Pipeline to Cushing				0.70	
Crude Oil Cost at Cushing		**20.00**		**20.00**	
Pipeline to Chicago		0.50	0.50	0.50	
Pipeline to Montreal	1.50	0.60	0.60	0.60	0.55
Delivered Cost at Montreal	**20.90**	**21.10**	**20.40**	**21.10**	**19.60**

While Capline appears to be a desirable option, over the longer term the system is expected to be at capacity, precluding incremental use of this line.

Other charges, such as for storage and handling, are deemed to be common to all carriers.

Appendix XII

Representative Light Sweet Crude Oil Supply Costs at Sarnia

($U.S. per barrel)

For the purpose of this analysis, it has been assumed that, for longer term planning purposes, WTI and Brent will be at parity in Cushing. Thus, the illustrative parity price has been set at $U.S. 20.00 per barrel, based on transportation from the U.S. Gulf to Cushing on the Arco/Texaco pipeline systems. This implies an F.O.B. Brent price of about $U.S. 17.80 per barrel.

	Canadian	WTI	Brent via				
			U.S. Gulf/ Capline	U.S. Gulf/ Arco/Texaco Pipeline	Portland/Sarnia- Montreal Reversal		
F.O.B.	19.40		17.80	17.80	17.80		
Ocean Freight			1.40	1.40	1.20		
Ocean Loss			0.10	0.10	0.05		
Landed Cost			19.30	19.30	19.05		
Pipeline to Cushing				0.70			
Crude Oil Cost at Cushing		20.00		20.00			
Pipeline to Chicago		0.50	0.50	0.50			
Pipeline to Montreal					0.55		
Pipeline to Sarnia*	1.15	0.25	0.25	0.25	0.30	-	1.25
Delivered Cost at Sarnia	20.55	20.75	20.05	20.75	19.90	-	20.85

While Capline appears to be a desirable option, over the longer term the system is expected to be at capacity, precluding incremental use of this line.

Other charges, such as for storage and handling, are deemed to be common to all carriers.

*Based on IPL's estimates, a range of tolls is quoted for the "reversal" illustration. The lower end of the range assumes throughput levels of about 285,000 b/d (45 300 cubic metres per day), while the higher toll applies to volumes of about 60,000 b/d (9 500 cubic metres per day), on a stand-alone basis. The rate for an integrated toll would be about $0.50 per barrel.

1.0 Deactivation

Two alternatives are available for the deactivation of the pipeline. The first involves displacing the linefill with crude treated with corrosion inhibitors, and the second involves purging the line and filling it with nitrogen. In both cases, if the company intends to deactivate its pipeline for a period of 12 months or more, it must obtain prior Board approval. Furthermore, should the deactivation be for a period longer than 12 months, the pipeline cannot be returned to operation without successful pressure testing.

Crude Fill Option

Should the pipeline be deactivated while filled with crude oil, it could be returned to service within 12 months upon short notice, provided that it is maintained in a proper state. A corrosion inhibitor would be injected at a high concentration to ensure each pipeline section has a uniform distribution of inhibitor. All connecting facilities such as pump stations and terminals would be isolated from the main line with the existing valves. No additional facilities are required.

The estimated cost of performing a one-time injection of inhibitor into the pipeline is $200,000. Prochem 5K5 is proposed as the inhibitor because it is compatible with existing refinery processes. It would take approximately 18 days to fill the line with inhibitor using four injection points, assuming that the Montreal refineries would be able to accept the untreated linefill being displaced by the treated crude. IPL injected inhibitors in January 1991.

It is expected that the shutdown-mode operating costs, which are necessary to keep the line maintained and in an operable state, would be approximately equal to the current operating costs. They are estimated at $7.3 million per year.

However, a line shutdown with crude fill is generally considered as a short-term option. Even with corrosion inhibitors, there are some concerns regarding long-term corrosion protection.

No environmental concerns beyond those normal to an operating crude pipeline have been identified for this option. The line pressure would be reduced to a minimum which would limit the impacts of any future leak.

Reactivation would be relatively rapid if the deactivation was for less than 12 months. The company would not be required to implement a pressure testing program. Since all equipment would be maintained in an operable state, the line could be reactivated almost immediately upon receipt of a supply of crude oil at Sarnia.

However, should the deactivation be for a longer period, the required pressure testing, using water as the testing medium, could take up to 4 months at a cost of $4 million.

Nitrogen Fill Option

Deactivation and displacement of crude oil with nitrogen in this line can be performed in four stages, one section of the pipeline at a time. The entire pipeline would be evacuated of product, pressurized with nitrogen to a minimum of one atmosphere of nitrogen, and cathodic protection would be maintained.

The one-time cost of purging the line and filling it with nitrogen is estimated at $1.8 million. As with deactivation with a crude linefill, the annual operating costs are estimated at $7.3 million.

The deactivation process would take up to four months, mainly as a function of the rates at which the oil could be received in Montreal.

However, this mode of deactivation reduces the weight of the total pipeline and could cause buoyancy problems. In order to avoid any upward movement, particularly in wet areas, during the initial construction of the pipeline, concrete weights were placed at certain sections of the pipeline to counter the buoyancy forces. It is expected that the pipeline is appropriately restrained in most, if not all, areas where buoyancy could be a problem. The company proposes to implement a pipeline monitoring programme to detect movement of the pipe. If pipe movement occurs, a restoration programme would be initiated the following winter to lower the pipeline and to install supplemental weighting to restrain the pipeline.

No environmental concerns were identified for the deactivation with nitrogen. The nitrogen fill is not considered environmentally harmful. However, there would be a need for surface restoration should any pipe lowering be required.

As with the deactivation with a crude linefill, if the line has been deactivated for 12 months or more, the Company would have to apply to the Board for approval. The Company would also be required to retest the line prior to reactivation. Retesting of the pipeline could take up to 4 months and cost $4 million.

Regulatory Requirements

The Board requires pipeline companies to meet the appropriate Canadian Standard Association Standard and the Board's *Onshore Pipeline Regulations*.

The applicable requirements of CSA Standard CAN/CSA-Z183-M90, entitled Oil Pipelines System, are as follows:

"Deactivation of Pipeline Systems

10.20.1

An operating company deactivating a pipeline system shall

(a) leave the pipeline system filled with an approved medium, and, where required, provided with pressure relief;

(b) isolate the pipeline system using blind flanges, weld caps, or blanking plates;

(c) maintain adequate records of deactivated lines; and

(d) maintain corrosion protection in accordance with the requirements of Clauses 9.2.4 and 9.4.4.

10.20.2

A deactivated pipeline system that is to be reactivated shall be examined and, where necessary, retested to establish its integrity for the intended service."

The Board's *Onshore Pipeline Regulations* adopt, by reference, the above standard, but also specify that the pipeline be retested prior to its reactivation if the deactivation lasts for 12 months or more, and such reactivation is subject to Board approval.

2.0 Reversal

For this study it is assumed that the greater part of the volume moving on a reversed Line 9 will be delivered to Sarnia from Montreal. The Toronto area refineries and export requirements to the United States would still be served via Lines 7 and 8 from Sarnia (see Figure XIII-I).

Phase 1 - reversal capacity of 45 500 cubic metres per day

In order to accommodate a reversal in the operation of the pipeline, an initiating station and associated manifold system would be required at the Montreal terminal. The reversal of the four existing pump stations could be accommodated by modifications to the existing pump units, or by their replacement with more efficient units designed for the lower flow rates.

In addition, break-out storage would be required at the Montreal pump station. Existing tankage may be available for leasing or purchase in Montreal. Otherwise, new storage facilities will be required.

In order to accommodate a reversal, the capacity of the upstream Portland-Montreal pipeline could be upgraded from 39 000 cubic metres per day to approximately 80 000 cubic metres per day with minimal effort.

It is estimated that the facilities on IPL required for a reversal will cost approximately $35 million,

including facilities providing for an eventual re-reversal. An additional $28 million may be required if the leasing of existing tankage facilities cannot be arranged at the Montreal terminal. The cost of the upgrade of the Portland-Montreal pipeline capacity would be in the order of $2 million.

It is estimated that the annual operating cost would be up to $28 million, depending on throughput.

The reversal could be implemented after one construction season, i.e., about 6 months.

Phase 2 - reversal capacity of 68 000 cubic metres per day

With the increased capacity, the pipeline operation would remain similar to that of Phase 1, however, additional facilities would be required.

The Phase 2 capacity expansion would require the installation of three new intermediate pump stations and the reinstallation of the original pump units in order to accommodate higher throughput volumes. It would also require the construction of additional tankage at Montreal, and the modification of IPL's Sarnia tank farm. The Portland-Montreal pipeline would be expanded by the construction of additional pump stations to increase the capacity of the system from 80 000 cubic metres per day to 95 000 cubic metres per day.

No additional connecting facilities would be required.

The new facilities are estimated to cost $9 million for the Portland-Montreal Pipeline, and between $65 and $95 million for the IPL system, depending on the final destination of the crude in Sarnia.

One construction season would be required to install the required facilities, i.e., about 6 months.

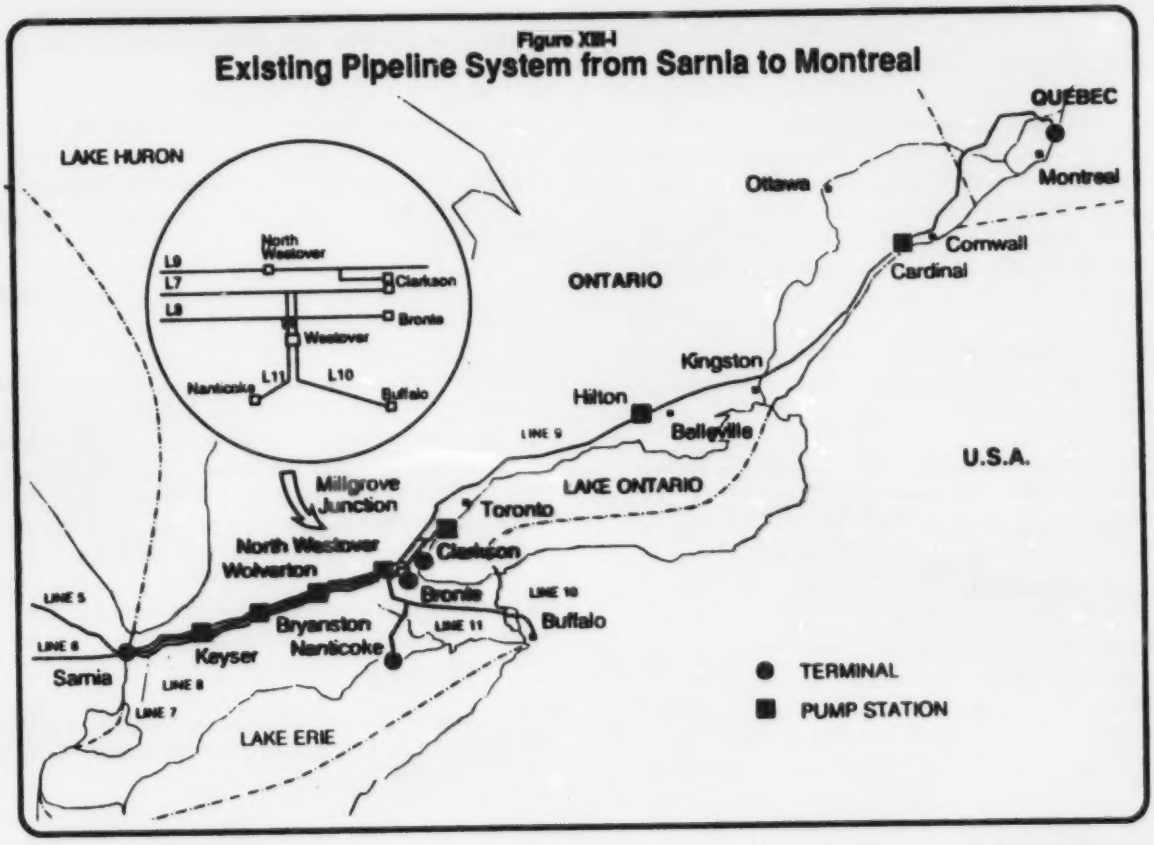
The annual operating costs are estimated at up to $50 million, depending on throughput.

Alternative pipeline operation

Presently crude oil deliveries from Sarnia via Lines 7 and 8 to Bronte, Clarkson, Nanticoke and Buffalo are in the order of about 46 000 cubic metres per day. With the reversal operation, the imported volume from Line 9 could replace all or part of the Ontario crude oil presently transported on Lines 7 and 8. This could allow a more efficient operation if the Ontario refineries were able to accept the imported feedstock. Assuming that crude requirements were compatible, imported crude from the Portland-Montreal pipeline could move on the Sarnia-Montreal pipeline from Montreal to North Westover, and the section of this line from Sarnia to Westover could be shutdown or deactivated. This alternative would allow the Company to remove Lines 7 and/or 8 from service. To implement this alternative, new break-out storage facilities would be required at the North Westover station, for crude deliveries to Bronte and Clarkson. Cross-over piping would be required at North Westover station to connect Line 9 to Lines 7 and 8 as shown in Figure XIII-1.

Figure XIII-I

Existing Pipeline System from Sarnia to Montreal



The preferred mode of operation of a reversed pipeline would likely be addressed during the review of a future application therefor by the Company.

Pipeline Integrity

The Company has implemented an ongoing pipeline integrity programme for detection of internal corrosion on the Sarnia-Montreal pipeline. It is expected that this programme will continue regardless of the mode of operation of the pipeline.

Since the pipeline was built, internal surveys have identified numerous indications of dents and buckles along the pipeline for which IPL has an ongoing monitoring and repair programme. With a line reversal, the pressure experienced by the pipe immediately upstream and downstream of pump stations would be higher or lower than that currently experienced. The pipeline at the suction side (thus lower pressure side) of the pump stations would now be subject to the higher discharge pressure. It would be difficult at this time to envisage any effects this may have on the integrity of the system. However, at the time of an application for reversal, IPL would be required to retest its pipeline if the deactivation lasted over 12 months. Such pressure testing is done at pressures significantly higher than the expected maximum operating pressures. Any significant defect can then be located and rectified.

The facilities for the Phase 1 reversal would be installed at existing pump stations or in already developed areas (Montreal tankage). Environmental consequences could therefore be considered negligible. Furthermore, the Phase 2 construction of new stations, although to be done on new lands, should not cause long term environmental damages. The construction effects are generally mitigable with known technology. However, there is a concern about the potential for new sources of noise emissions as a result of the operation of the new pump stations.

3.0 Bi-directional Flow

Seasonal Operation

The direction of flow may be from west to east during certain months of the year to provide Montreal refineries with crude oil or to allow for heavy crude exports out of Montreal; for the remainder of the year the flow would be east to west to supply Ontario refineries with imported crudes.

The facilities proposed for the reversal of the operation would accommodate the re-reversal of the system, without additions.

The annual operating costs would be similar to those of the reversed pipeline, at equivalent throughputs.

Yo-yo Operation

A yo-yo operation involves a more frequent change in direction and requires delivery at high volume rates and a large volume of tankage. Under this option, when Montreal receives a crude batch for delivery to Sarnia, the entire linefill ahead of the batch will be delivered to Sarnia tankage. The reverse is true for any crude moving to Montreal from Sarnia.

For this operation IPL would be required to pump at a rate of 68 000 cubic metres per day to Montreal for 2.5 days, into Sarnia for 15 days, and moving linefill volume for 12.5 days in every 30 day period.

This option would cause IPL some very significant operational difficulties.

Furthermore, the facilities described for the Phase 2 reversal would be required to be supplemented by the construction of substantial tankage facilities at Sarnia and Montreal, at an estimated capital cost of $200 million. The operating costs for this option are estimated at about $65 million per year.

Two construction seasons may be required for this option due to the large amount of required tankage.

The environmental concerns associated with the bi-directional flow are similar to those described for the reversal.